Integrated Resource Plan and Master Plan

Volume 2 Master Plan Transmission and Distribution

Columbia Water and Light

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1 Executive Summary

Utilities around the U.S. are facing a variety of new challenges with the traditional business model being challenged from intermittent renewable energy, distributed generation, the push for environmental responsibility and ambitious environmental targets, among others. All within the objective to maintain or limit customer rate increases. The Integrated Resource Plan and Master Plan Study seeks to cover these challenges for Columbia Water and Light and evaluate different scenarios that the utility could face in the future, not only from the generation planning perspective and demand growth but also in terms of the transmission and distribution and metering infrastructure required to operate and manage the system in the future.

The Integrated Resource Plan and Master Plan Study report is organized in two volumes, this Volume 2 and Volume 1 that covers the aggregated load forecasts including Energy Efficiency, Demand Side Management, distributed generation forecast, and the projected generation capacity expansion options considered.

This Volume 2 discusses the results of the spatial load forecast that allocates geographically to CWL service territory the aggregated load forecast presented in Volume 1 (Section 3) and the impact that this allocation has on the transmission to distribution substations in terms of their coverage areas and need for expansion (Section 4).

Volume 2 next provides the result of a detailed analysis of the CWL distribution systemin the short (2025), medium (2030) and long term and identified the need for reinforcements including Non Wires Alternatives for attending the expected load growth and the integration of distributed solar generation using the projections presented in Volume 1 (Section 5).

Section 6 provides the assessment of CWL transmission system over the same time horizons above including the requirements for the interconnection of new local generation (the Boone Stephens Solar). It presents the vulnerabilities of the system and identifies alternative solutions.

Section 7 provides the results of a review of CWL Engineering standards and Section 8 presents a summary of the capital expenditures derived from the analysis in the prior sections.

We summarize the results of these studies below.

The spatial load forecast results indicated that the CWL system is expected to grow predominately towards the north and east, with Bolstad expected to see the highest load growth followed by Blue Ridge, Grindstone and Rebel Hill. The substations to the west and southwest (Harmony Brach and Perche Creek) are expected to experience lowest growth. The table below shows the expected growth by substation.

Table 1-1: Load by substation MW

Substation	2020	2025	2030	2040	Change 2040/2020
Blue Ridge	23.80	23.91	24.98	27.94	117%
Bolstad	14.26	16.20	19.10	25.32	178%
Grindstone	34.90	36.79	37.54	40.87	117%
Harmony Branch	40.47	40.12	39.61	40.98	101%
Hinckson Creek	45.01	44.37	44.74	47.30	105%
Perche Creek	35.03	35.03	34.36	35.43	101%
Power Plant	47.55	47.29	47.63	50.74	107%
Rebel Hill	31.73	32.52	33.14	36.03	114%
Total	**273**	**276**	**281**	**305**	**112%**

The analysis of the transmission to distribution substation with current and forecasted load allocated from the spatial load forecast, identified that several substations would not meet CWL planning criteria and there would be overloads in the case of one transformer failure at the substation. To address this, as shown in Section 3, the coverage areas (service areas) of several substations were reconfigured so that the expansion needs were concentrated at substations where there was space for an additional transformer. A new substation was considered as an option, but at this time it cannot be justified given the location of projected growth of CWL load. Table 1-2 shows the recommended transformer additions by substation where we observe that most additions are recommended on the short term (2025), Bolstad and Rebel Hill because of the load growth and Perche Creek to attend its current loading. There is a fourth transformer recommended for Harmony Branch in the long term (2040), but this can probably be indefinitely postponed using some of the load transfers and investment identified in the Distribution Analysis Section 5

Table 1-2: Substation Installed Transformer Capacity

Future capacity	2020	2025	2030	2040	Observation
Substation	**[MVA]**	**[MVA]**	**[MVA]**	**[MVA]**	
Bolstad	**44.8**	**67.2**	**67.2**	**67.2**	**Add a third 22.4 MVA Transformer by 2025**
Blue Ridge	**44.8**	**44.8**	**44.8**	**44.8**	
Grindstone	**67.2**	**67.2**	**67.2**	**67.2**	
Harmony Branch	**67.2**	**67.2**	**67.2**	**89.6**	**Add a fourth 22.4 MVA Transformer by 2040**
Hinkson Creek	**67.2**	**67.2**	**67.2**	**67.2**	
Perche Creek	**44.8**	**67.2**	**67.2**	**67.2**	**Add a third 22.4 MVA Transformer by 2025**
Power Plant	**67.2**	**67.2**	**67.2**	**67.2**	
Rebel Hill	**56**	**84**	**84**	**84**	**Add a third 28 MVA Transformer by 2025**
New Substation	***0***	***40***	***40***	***40***	***At least 2 x 20 MVA required (option not recommended)***

CWL distribution system is not expected to experience overloads or significant voltage violations during peak load and normal operating conditions (system intact) over the short term (2025) and only slight overloads at one Blue Ridge substation feeder exit (feeder BR222) by 2030. Over the long term (2040) various substation feeder exits in addition to Blue Ridge; Grindstone, Hinkson Creek, Rebel Hill and Bolstad would overload if no investments are made on the system. Low voltage performance violations are concentrated at the water treatment plant area, but these are not critical (above 0.95 pu).

Under emergency conditions, which assess the ability of a feeder to provide backup to an adjacent feeder and supply its load in case of an outage, several limitations were identified during peak load, and investments proposed to address them. These investments also address the normal operating condition overloads identified in the medium (2030) and long term (2040).

The investments we grouped in 20 distinct projects and most of them consist of changing the conductor on short feeder sections or adding a short new feeder section to allow interconnection and load transfers between feeders. The largest investments are associated with Perche Creek, Rebel Hill and Bolstad and are detailed next.

The largest investment is a new feeder out of Perche Creek to provide backup to the Wastewater processing facility and extending to the residential area South of Perche Creek to provide backup that this load currently lacks. This is identified as Project 11 and an alternative using PV and Batteries was proposed to provide backup in lieu of the feeder extension to the residential area. Additionally, a new feeder (Project 8) is proposed for Perche Creek, but the investments are largely inside the substation as this new feeder has a short section connecting to the existing PC223 that is partially transferred to the new feeder

The second largest investments are associated with Rebel Hill and include two new feeders to alleviate overloads during emergency conditions (Project 17) support the load transfers from Grindstone (Project 20). Additionally, there is a need for a longer feeder section (Project 19) to transfer load from Blue Ridge to Rebel Hill. These investments add flexibility to the network by stablishing new connections and NWA would not be good substitute as, unlike the case of the residential area above, there are no loads that can be easily isolated.

In addition to the above a new feeder (Project 4) is proposed out of Bolstad to be implemented together with the new transformer to address both normal and emergency conditions overloads. The balance of these investments are small and include capacitor banks for power factor correction and voltage support and detailed in Section 5.

Section 5 also covers the performance of the system with the investments recommended that is projected to be adequate under the short, medium and long term and the analysis under light load and high distributed generation dispatch, also showed that no additional investments would be necessary, beyond adjusting the taps of the transformers at the substations. Finally, this section confirms the need to expand the transformation capacity at Perche Creek, Bolstad and Rebel Hill by 2025 but not at Harmony Branch even in the long term.

Based on the analysis of CWL transmission system (Section 6) it is concluded that this system is expected to perform adequately and within NERC standards without the need of any major investments in the network, beyond those already defined for the new line UMC to Grindstone and the upgrade of the line Hinkson Creek to UMC.

However, there were multiple conditions occurring with two or more elements out of service that would require mitigation including load shedding or redispatch of the CEC depending on the event. A non-wires alternative was provided for this load shed risk consisting of a solar array and a battery energy storage, with an effective cost of about $40 million. This should be compared with other options that CWL is evaluating to reinforce its system.

Finally, if the UMC requests a firm transfer the new lines to the university should be rated 122 MVA instead of 107 MVA and the UMC would necessitate to keep its internal generation to address the interruption of the firm transfer during outages of two or more elements (N-1-1), unless the system is reinforced to prevent these N-1-1 overloads.

Section 7 presents a review of CWL engineering standards are recommends new standards to be developed in three tranches. The first tranche of standards to be developed cover the new, emerging areas including Plug-In Electric Vehicle Interconnections and Inverter Connected Assets. The second and third tranches cover the more complicated existing classes of assets (Control and Monitoring Systems, Substations and Metering Equipment) and the remaining proposed standards (1. Low Voltage Distribution Lines and Civil/Structural Design), respectively. A timeline and cost of developing the standards is proposed.

Finally, Section 8 provides a summary of the transmission level investments for the NWA and the capital investments which are summarized in the tables below.

Table 1-3: Non Wires Alternative Capital Cost

	MW	$/kW	Capital Cost $M
Storage (BESS)	27	1,234	33.3
PV	30	1,154	35.6
Total			**67.9**

Table 1-4: CWL CapEx budget for each term

CWL Investments	Cost [$]			
	2025	2030	2040	Total
Distribution Level	**$36,869,668**	**$2,933,495**	**$6,555,517**	**$46,358,680**
Underground Cable	$18,580,462	-	-	$18,580,462
Breaker & Switches	$3,473,932	-	$80,250	$3,554,182
Distribution Transformer	$14,456,835	$2,892,763	$6,340,852	$23,690,450
Capacitor Bank	$358,440	$40,732	$134,415	$533,587
Transmission Level	**$4,610,134**	**$0**	**$0**	**$4,610,134**
Power Transformer	$2,143,063	-	-	$2,143,063
Breaker	$2,467,071	-	-	$2,467,071
Total	**$41,479,802**	**$2,933,495**	**$6,555,517**	**$50,968,814**

As pointed out in this Section 8 the effective cost of the NWA, once the benefits of supplying the load and providing meeting the Renewable Energy targets are taken into consideration is $ 41 million effective cost.

2 Overview of Master Plan Methodology

A master plan is an instrument that serves a utility like CWL to gain a long term view on how the system should evolve and serves as a guide for the investment decision making for short and medium term by providing a view of how these investments fit on the overall development of the system.

The overall procedure followed in this report consist of the following steps:

1- **Spatial Load Forecast.** In this first step the aggregated load forecast developed using economic and population data is geographically located to the places where the load is most likely to appear. This is central as it will provide information on how the city is likely to grow and where the future needs will be concentrated.

2- **Substation Expansion and Coverage Areas.** Next based on the above the future load for existing and potential new substations is determined. This is needed both for the evaluation of the transmission system assessment that will supply those substations and for the study of the distribution system that will start from them. The substations and coverage areas defined in this step are preliminary as it may be refined as is frequently the case during the study of the distribution system that can affect the coverage area or the transmission system that alters the location of a new proposed substation or adds a new switching substation for reliability needs.

3- **Distribution System Assessment:** This study similar to the transmission study includes a short 5 years, medium 10 years and long 20 years planning horizon. This is done with the objective of making sure that the short term decision result in optimal plans for the long term and avoid the patching of short term solutions that end of costing more and result in a less reliable system. In this step the medium voltage system is assessed under normal and emergency conditions and performance shortcomings (also known as violations) are identified. The process then selects from various candidates, those solutions that best address the violations and include the reinforcements of existing system or new feeders when this is the most adequate solution in the medium and long term. In this assessment non-wires alternatives (NWA) are always an option to be considered and it proposed when due to the extension of the future traditional expansions are like to be more costly. The study also assesses the impact that distributed energy resources (DER) will have on the network and identifies required investments for the system to host the expected DER growth. This phase ends with a model for the distribution system as is expected to evolve, a final view of the loading at the substations and a prioritized list of investments.

4- **Transmission System Assessment:** This study follows a methodology that we call jump ahead and stage back. The study starts looking at how the system will look in the long term considering the substation loads identified in the prior steps and the local generating resources (if any) identified on the IRP. These future needs and resources are modeled in the existing system and its performance under normal and contingency conditions is assessed following CWL and NERC standards. Performance violations are identified, and least cost solutions are selected from a set of candidate solutions that if appropriate include NWA. Then system is assessed in the short and medium term and the in service date for these solutions is selected based on the determined emergence of the issues that triggered these investments. Like the distribution plan this section ends with a model for the system over the planning horizon and a prioritized list of investments with their projected in service dates.

5- Standard Review: This is a supporting section of the master plan and reviews the engineering standards and NERC filings that would apply to the utility and identifies the changes in the standards that would be required to be added or modified as a result of the type of investments that are identified in the sections above or could be part of it in the future.

6- **Capital Projects:** This is another supporting section and in it the capital investments identified in the master plan are summarized including the priority and if available they are contrasted with the plans currently ongoing by the utility.

7- **AMI and Smart Grid Investments.** This part of the study concentrates on the advanced measurement infrastructure and other measuring and control devices that utility should consider investing on to efficiently address the challenges of increased distributed energy resources, reliability, environmental responsibility, and increased transparency. The section covers the smart grids and new business strategies that the "utilities of the future", should consider to manage the demands of intermittent renewable energy sources, improve operational excellence, and reshape their businesses.

The study presented in this report followed each of the steps presented above

3 Spatial Load Forecast

3.1 Introduction

In this section it is presented the criteria and procedure performed for the Spatial Load Forecast that provides the core information used to determine the proposed expansion and coverage area for the existing and new substations and the distribution system analysis presented in following sections.

The Load Forecast for the entire system was presented under Part I--2 System Load and Energy Forecast, and in this chapter, starting from this aggregated forecast the spatial load forecast is performed.

There are several steps that must be followed for an effective spatial load forecast. These steps include:

- Use of the City Zoning data to create a map with the areas where existing consumers are located, and possible new consumers will appear.
- Analysis of the area for each zoning type in the service territory.
- Analysis of the load at system peak.
- Observe the area and zoning using aerial and satellite Images to determine which area has possibility to growth and empty spaces.
- Construct a model in Excel to compute the possible load growth of each cell.
- Determine the Substation coverage area to determine the current load supplied by the substations
- Compute the load growth for each area and based on it, the forecasted substation transformers loading.
- Determine if the substations (transformers) can handle the new load in their coverage area, and if not adjust the coverage area transferring load to other substations (new or existing) or determine the possibility of a substation expansion
- Present the proposed changes in coverage areas for each term and the proposed expansion in case it is needed.
- Show the summary of the substations expansion or changes needed.

We present each of these steps below.

3.2 Zoning Map Creation and Zoning Processing

The spatial load forecast uses zoning information to calculate the indexes of electric demand by type of customer load, therefore the proper processing of zoning GIS data is fundamental.

In the case of Columbia, the zoning GIS data was provided by the city itself, within the file “Current Zoning.SPH”. This file had multiple types of zonings and after some processing it was identified that the actual zoning was included in the “type 0” polygons and the different types of zoning were reduced from over 50 to only 13. The figures below shows the results before and after the filtering

Figure 3-1 Columbia City Zoning Map

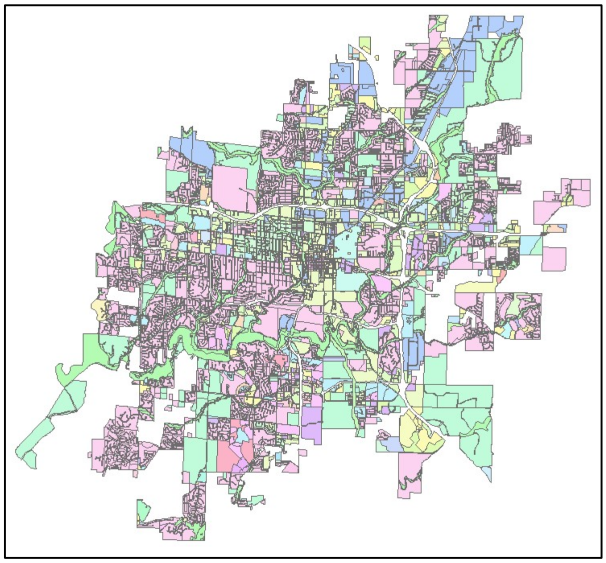
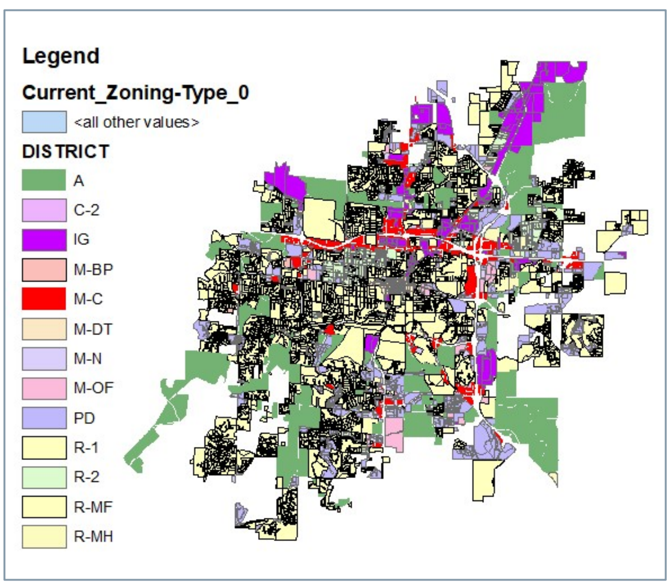


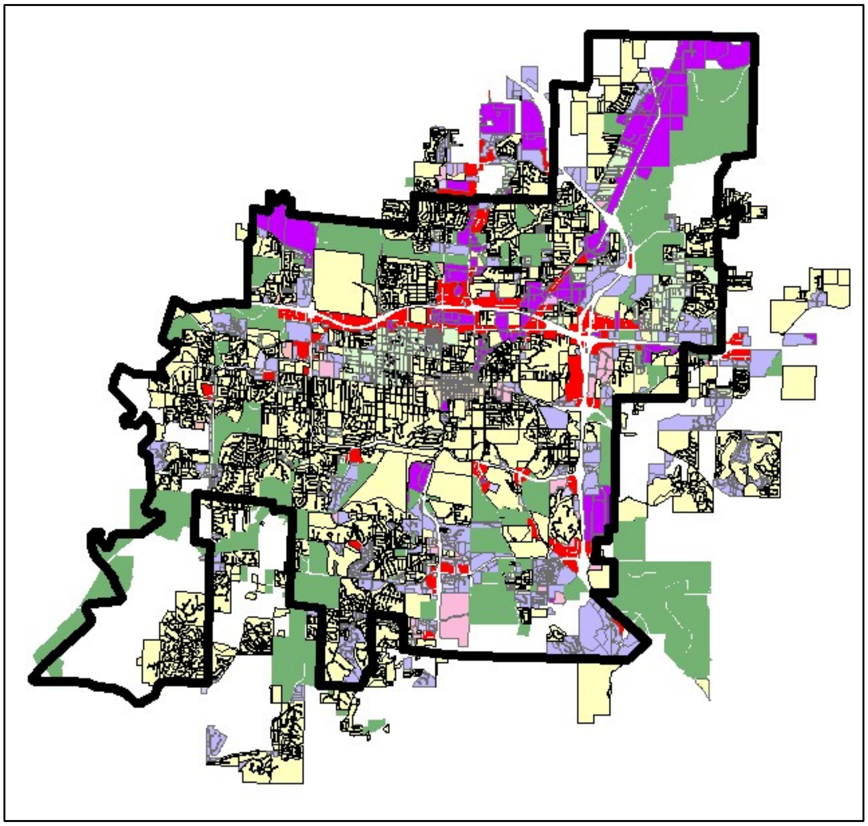
Figure 3-2 Columbia City Zoning Map - Filtered



In Figure 3-2, the zoning files are listed on the left side with the color they have in the map. This zoning map includes the entire city limits that extends beyond CWL service territory. Figure 3-3 shows in with a thick black line the border of CWL's service area.

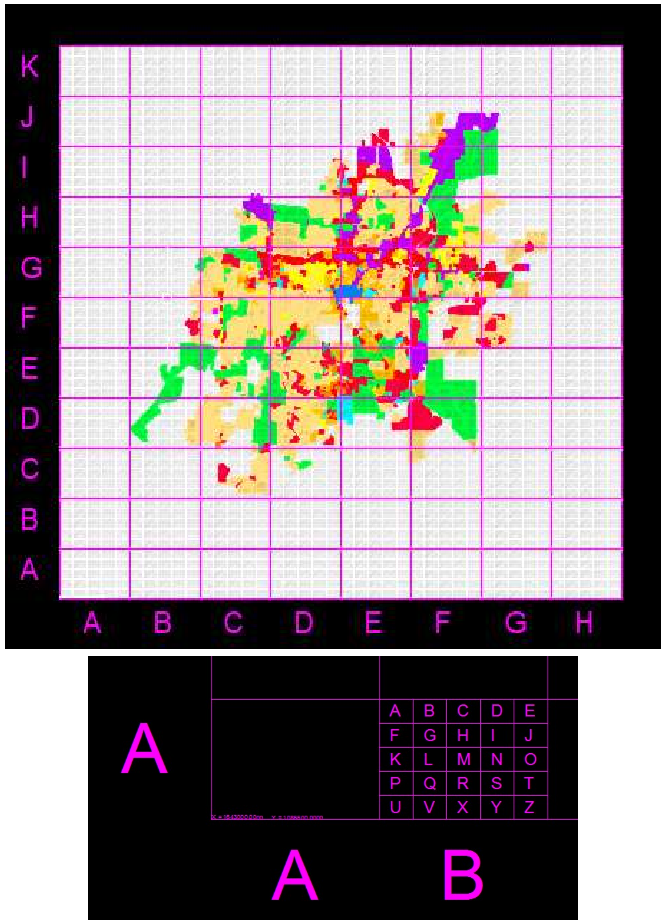
As it can be seen on this figure, there are zoning areas outside CWL service area. When processing these outside areas the information is maintained and labeled "no zone" or "other", in this way the integrity of the data is maintained.

Figure 3-3 Columbia City Zoning Map & CWL Service Territory



The next step is to divide the area in cells of a grid. It is alphabetical with 25 letters. This grid uses row and columns to identify each 11200 ft x 8000 ft quadrant and each of these quadrants is divided into 25 cells of 2240 ft x 1600 ft, arranged in 5x5 from A to Z identified with a letter (as shown in Figure 3-4). Therefore, each cell is identified with the Column letter, the Row letter and the arrange letter; GJU or AJA. From now these are going to be the cell's name.

Figure 3-4 Map Grid & Cells



Next we summarize how much area by cell is occupied by each zoning type. This was done with the GIS data and a simple process in excel. Figure 3-5 shows a partial view of the resulting table.

Figure 3-5 Zoning Matrix – Partial view

	MU	R-1	PD	A	R-MH	M-N	R-MF	R-2	M-OF	M-C	Other
BEU	0	0	0	0	0	0	0	0	0	0	3584000
BEV	0	0	0	0	0	0	0	0	0	0	3584000
BEX	0	0	0	2681689.477	0	0	0	0	0	0	902310.5228
BEY	0	0	0	2164763.093	0	0	0	0	0	0	1419236.907
BEZ	0	0	0	0	0	0	0	0	0	0	3584000
CEU	0	388265.225	0	0	0	0	0	0	0	0	3195734.775
CEV	0	1656546.838	0	0	0	0	0	0	0	0	1927453.162
CEX	0	1234637.295	0	374170.1825	0	0	0	0	0	0	1975192.523
CEY	0	947365.1954	0	1100525.028	0	0	0	0	0	0	1536109.777
CEZ	0	846501.5115	0	2252704.167	0	0	0	0	0	0	484794.3215
DEU	0	1576.361111	0	3445868.826	0	0	0	0	0	0	136554.8131
DEV	0	2052256.853	327023.849	716309.8681	0	0	0	0	0	0	488409.4302
DEX	0	1575039.995	1475007.891	716.2950197	0	0	0	0	0	0	533235.8189
DEY	0	935039.8409	1239150.194	100778.4664	0	359959.8318	284973.6998	0	0	0	664097.9675
DEZ	0	115237.7874	197560.132	0	0	1018998.969	288190.4958	0	65512.85057	945235.3559	953264.4094
EEU	0	0	1812268.659	206401.9794	0	658901.8034	23852.41229	0	359965.6541	0	522609.4921

This result is used to establish the load index by zone and the electric saturation by cell as discussed later.

3.3 Load Limit to the spatial Load Forecast

The city's electric load forecast presented earlier in this report provided the gross demand and its modifiers; energy efficiency (EE), the electric vehicle power demand (EV) and distributed generation (PV). These results are shown in the table below.

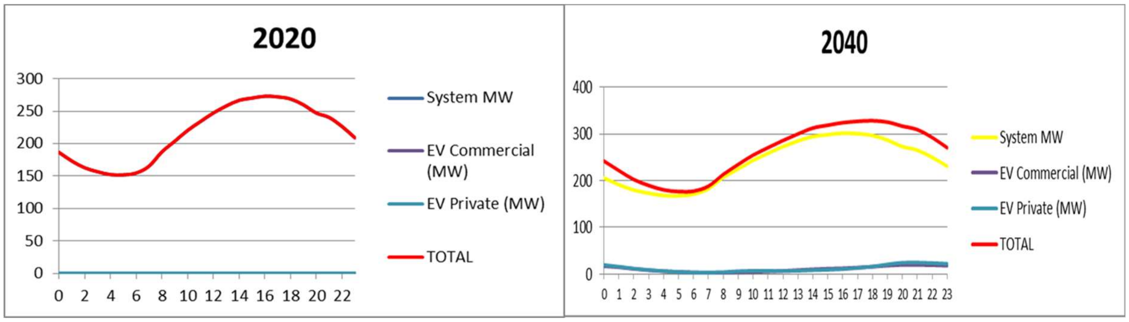
Four years were selected for the spatial load forecasting; 2020 as starting point, 2025 as close range, 2030 as medium range and 2040 as long range.

Table 3-1: Summary Results from Load Forecast (MW)

Year	Gross (MW)	PV	EE	EV	Net (MW)
2020	274.6	0.18	1.6	0.2	273.0
2021	276.8	0.25	3.3	0.3	273.6
2022	279.1	0.31	4.9	0.4	274.2
2023	281.3	0.42	6.6	0.5	274.8
2024	283.5	0.64	8.2	0.6	275.2
2025	285.8	1.05	9.9	0.8	275.6
2026	288.0	1.68	11.6	1.0	275.7
2027	290.2	2.53	13.3	1.2	275.6
2028	292.4	3.56	15.0	1.5	275.3
2029	294.7	4.70	16.8	1.8	275.0
2030	296.9	5.91	16.9	2.1	276.2
2031	299.1	7.14	17.0	2.5	277.5
2032	301.3	8.40	17.1	2.9	278.7
2033	303.6	9.68	17.2	3.3	280.0
2034	305.8	10.97	17.3	3.7	281.2
2035	308.0	12.28	17.4	4.2	282.5
2036	310.3	13.59	17.6	4.6	283.7
2037	312.5	14.90	17.7	5.1	285.0
2038	314.8	16.22	17.8	5.5	286.3
2039	317.1	17.54	17.9	5.9	287.5
2040	319.4	18.87	18.0	6.3	288.8

As the modifiers evolve over time, this changes the shape of a typical day, therefore a parameterization of their behaviors was performed so that the actual peak of a typical day can be estimated. The figure below shows how the demand curve of the system changes from 2020 to 2040.

Figure 3-6 Load Profile with EV



This analysis shows that the peak of the demand moves from 4pm to 5pm due the increase of electric vehicle demand.

One important consideration is that the Energy Efficiency gains (load reduction) are more likely to occur on the existing customers and not for the new customers or loads that are not likely to require improvements in their installations. Also, a vegetative load increase of 0.6 % for the residential existing loads was applied to consider the possibilities for new loads being added by exiting customers These considerations were used for the calculation of the new load to be allocated and are shown in Table 3-2 and Table 3-3.

Table 3-2: Energy Efficiency consideration

				Vegetative	0.60%											
	Existing Load no EV			Adjustments												
Year	C&I	Residential	Total	Resdential Vegetative Growth	Less EE	Adjusted Existing Load no EV	New Load no EV	Total Load No EV	Existing Load Ratio	EE Reduction	Aditional EV Load Industrial (MW)	Aditional EV Load Residential (MW)	Adjusted Existing Load with EV	New Load (MW)	Total Load with EV (MW)	Existing Load Ratio
2020	158	117	274.6	-	(1.6)	273.0	-	273.0		1%	0.05244478	0.04445118	273.09	-	273.09	
2021	158	117	274.6	0.7	(3.3)	272.1	1.5	273.6	100%	1%						
2022	158	117	274.6	1.4	(4.9)	271.1	3.0	274.2	99%	2%						
2023	158	117	274.6	2.1	(6.6)	270.2	4.6	274.7	99%	2%						
2024	158	117	274.6	2.8	(8.2)	269.2	6.1	275.3	99%	3%						
2025	158	117	274.6	3.6	(9.9)	268.3	7.6	275.8	98%	3%	0.21347914	0.18094078	268.65	7.58	276.23	98%
2026	158	117	274.6	4.3	(11.6)	267.3	9.1	276.4	98%	4%						
2027	158	117	274.6	5.0	(13.3)	266.3	10.6	276.9	98%	5%						
2028	158	117	274.6	5.7	(15.0)	265.3	12.1	277.4	97%	5%						
2029	158	117	274.6	6.5	(16.8)	264.3	13.6	277.9	97%	6%					-	
2030	158	117	274.6	7.2	(16.9)	265.0	15.1	280.0	97%	6%	0.58530529	0.49609344	266.05	15.05	281.10	97%
2031	158	117	274.6	8.0	(17.0)	265.6	16.5	282.1	97%	6%						
2032	158	117	274.6	8.7	(17.1)	266.2	18.0	284.2	98%	6%						
2033	158	117	274.6	9.5	(17.2)	266.9	19.5	286.4	98%	6%						
2034	158	117	274.6	10.2	(17.3)	267.5	20.9	288.5	98%	6%						
2035	158	117	274.6	11.0	(17.4)	268.2	22.4	290.6	98%	6%						
2036	158	117	274.6	11.8	(17.6)	268.8	23.9	292.7	98%	6%						
2037	158	117	274.6	12.5	(17.7)	269.5	25.4	294.9	99%	6%						
2038	158	117	274.6	13.3	(17.8)	270.1	26.9	297.0	99%	6%						
2039	158	117	274.6	14.1	(17.9)	270.8	28.4	299.2	99%	6%						
2040	158	117	274.6	14.9	(18.0)	271.4	29.9	301.4	99%	6%	1.74785191	1.48144545	274.67	29.94	304.61	101%

Table 3-3: Results Summary

Year	Forecast With EE (MW)	New Load with EE & EV (MW)
2020	273.09	0.00
2025	276.23	7.58
2030	281.10	15.05
2040	304.61	29.94

3.4 Spatial Load Processing

To construct this model, the current load on the system was obtained combining different sources of data provided by the CWL.

- The transformer list (location, capacities and labels) was obtained from the CWL GIS model.
- This list was completed with new equivalent transformers for the industrial customers served directly in 13.8 kV. With primary meters. (measurements at 13,8 kV).
- Feeder Head Load values (5 minutes)
- Energy data for each customer account linked to the transformers.

With a complete list of transformers and primary metered customers located, the next step is to assign the demand related to the period relevant to the study. After the analysis of the system demand and feeder head load real time records it was decided to use the 2019 data as it is complete and there is matching between GIS and Energy data.

The System peak load was on July 19th 2019; using power factors and the energy sold that month we calculated each feeder load factor and used it to convert the transformer energy billed that month into demand, as shown in Figure 3-7. This transformer demand was then adjusted to match the feeder loading at time of system peak.

Figure 3-7 Billed July Transformers List Partial View

(ACCOUNT)	Days	Consumption (kWh)	TL	FeederID
0073768	29	1288	6453	RH224
0053010	29	75	11805	PP222
0099875	29	151	2587	HC221
0116466	29	1537	8648	BR212
0049756	29	2880	285	PP214
0147410	29	1407	10035	HB233
0048030	29	34	944	PP221
0055458	29	1605	10632	HC221
0136370	29	3528	1332	RH224
0113214	29	1359	5861	PP231
0136322	29	3796	2669	HC211
0126498	29	4800	165	PP232
0014744	29	405	3031	HC221
0172312	58	1548	11653	HC221
0065476	29	1099	10149	RH224
0063106	29	220	3395	BR222
0158774	29	3505	11053	HC231
0046778	29	11	651	PP213
0122484	29	1760	5646	PC213
0027842	29	131	512	GS232
0049336	29	783	27	RH224
0065660	29	1910	3557	PP233
0167206	29	4671	10336	BR211
0155081	29	552	964	PP221
0012622	29	226	4110	PC212
0049758	29	635	285	PP214
0148010	29	5058	10293	PC222
0047946	29	1632	1719	PP222
0162140	29	584	10049	GS211
0074854	29	1476	9993	RH224
0060942	29	723	6413	RH214
0006746	29	6011	4989	PC212

(ACCOUNT)	Days	Consumption (kW)	TL	FeederID
0059330	29	11.67	5613	BR212
0137646	29	9.26	180	PP232
0037516	29	14.54	2738	HC211
0174736	29	24.71	718	PP223
0157416	29	1.96	5648	PC213
0044482	32	8.22	4856	RH213
0114996	29	20	215	BR222
0069616	29	0	1809	RH224
0147040	29	14.26	10392	BR212
0022076	29	15.9	6674	HC223
0143368	29	1.32	174	PP232
0128934	29	8.1	9006	PC211
0144366	29	9.42	3913	HB232
0037564	29	5.67	2629	HC211
0158720	29	10.43	174	PP232
0129130	29	12.27	9004	HC211
0157038	29	3.86	736	HC221
0044614	29	6	4376	RH221
0161044	33	3.95	10554	PP232
0153976	58	22.62	10778	BR222
0157866	29	20.45	737	PC222
0167008	29	3.51	10919	PC222
0137210	29	15.27	1831	RH211
0133208	29	12.04	9528	HC221
0114938	29	14.31	5861	PP231
0099540	29	7.68	6013	HC231
0148880	29	10.06	10033	GS222
0073996	29	3.96	4063	HB212
0026686	33	4.75	157	PP223
0155106	29	13.7	10336	BR211
0026094	29	8.2	730	RH212
0065356	29	14.4	3382	PP212

	(ACCOUNT)	TL				Feeder ID	Demand
	0	0					
44	116	3209	0	29	169	PP213	0.410216342
44	118	3209	0	29	47	PP213	0.114083835
44	120	3209	0	29	268	PP213	0.650520589
44	122	3209	0	29	213	PP213	0.51701823
44	124	3209	0	57	1523	PP213	1.880828939
44	126	3209	0	29	240	PP213	0.582555752
44	128	3209	0	29	435	PP213	1.0558823
44	130	3209	0	57	771	PP213	0.952146495
44	132	3209	0	29	180	PP213	0.436916814
44	134	3209	0	29	507	PP213	1.230649025
44	138	3209	0	29	485	PP213	1.177248081
44	140	3209	0	29	357	PP213	0.866551681
44	142	3209	0	29	156	PP213	0.378661239
44	144	3209	0	57	205	PP213	0.253164762
44	150	3208	0	29	159	PP213	0.385943185
44	152	3208	0	29	642	PP213	1.558336636
44	154	3208	0	29	654	PP213	1.587464423
44	156	3208	0	30	144	PP213	0.337882336
44	158	3208	0	29	1041	PP213	2.526835573
44	160	3208	0	29	292	PP213	0.708776164
44	162	3208	0	29	189	PP213	0.458762654
44	164	3208	0	33	112	PP213	0.238906702
44	166	3208	0	29	429	PP213	1.041318406
44	168	3208	0	29	1068	PP213	2.592373095
44	170	3208	0	29	209	PP213	0.507308967
44	172	3208	0	29	144	PP213	0.349533451
44	174	3208	0	29	747	PP213	1.813204777
44	178	3208	0	29	519	PP213	1.259776813
44	180	3208	0	12	30	PP213	0.175980383
44	182	3208	0	29	409	PP213	0.992772093
44	184	3208	0	57	661	PP213	0.816301989

Then we need to match the System Load projection for 2020 as it is the starting point for the Load Forecast Study. To accomplish this, proportional adjustments were made using the Feeder Head Load at System peak Time, first to match the Feeder Head loads, second to match the forecasted relation Residential / Commercial & Industrial and finally to match the total System Load. In the File: Spatial Load Allocation-Transformer LOADS_VF.xlxs Tab: "Load Adjusting" is presented the final results for 2020.

Figure 3-8 Adjusted 2020 Load in each Transformer partial view

TL	Feeder ID	Capacity	Transformer Customer Type	Final kVA	Final kW	Final kVAr	Final Power Factor	x	y
2	PP214	1x150	C or I	99.18974034	84.31127929	52.251438	0.85	1687387.665	1140042.067
4	PP222	1x112.5	C or I	55.06563554	46.80579021	29.00762348	0.85	1694917.54	1140406.888
5	PP214	1x50	Residential	13.60461046	12.78833383	4.641545385	0.94	1687401.202	1139538.128
6	PP214	1x112.5	C or I	30.11226521	25.59542543	15.86262	0.85	1687565.897	1139505.346
7	PP214	1x150	C or I	70.20068611	59.6705832	36.9805061	0.85	1687055.286	1140048.404
8	PP212	1x225	C or I	55.5855629	47.24772847	29.28151222	0.85	1687394.039	1140804.056
9	PP214	1x150	C or I	26.49756806	22.52293285	13.95846012	0.85	1687449.21	1139900.661
10	PP214	1x25	C or I	9.690247435	8.236710319	5.104654588	0.85	1687620.34	1138568.445
11	PP213	1x37.5	Residential	8.744163202	8.65672157	1.233516017	0.99	1687495.366	1138887.039
12	PP213	1x37.5	Residential	13.31976064	13.18656303	1.878983467	0.99	1687166.894	1138893.202
13	PP213	1x75	C or I	30.70590096	26.10001582	16.17533703	0.85	1687455.262	1138770.199
14	PP213	1x15	Residential	12.87062224	12.74191602	1.815624698	0.99	1687294.879	1138603.626
15	PP223	1x300	C or I	94.83527027	80.60997973	49.95757856	0.85	1688065.355	1134780.817
16	PP214	1x25	Residential	6.624984184	6.293734975	2.068650649	0.95	1687612.441	1138000.563
17	PP214	1x37.5	Residential	11.70015206	11.58315054	1.65050956	0.99	1687325.462	1137872.192
18	PP214	1x50	Residential	18.50833303	18.3232497	2.610921675	0.99	1687069.743	1137907.132
19	PP213	1x50	Residential	25.68510218	25.42825116	3.623329551	0.99	1686182.763	1137481.565
20	PP214	1x37.5	Residential	7.168879297	7.097190504	1.011294875	0.99	1687233.76	1137588.362

The resulting transformers load represents the load forecasted for 2020 with the same spatial allocation of 2019, and it is the starting point for the further analysis.

3.5 Load index by zoning and cell saturation

The next step for the spatial load allocation is to calculate the index of demand by zoning area and the cell's electric saturation. To accomplish this, two different procedures are needed. The first is to calculate the actual (2020) demand (kW and kVA) modeled for each cell; the second is to obtain each Zoning Demand Index; this is the consumption KVA per area (million sqft) for each zoning type.

The first procedure entails summing-up the demand of all transformers inside each cell in the Service territory.

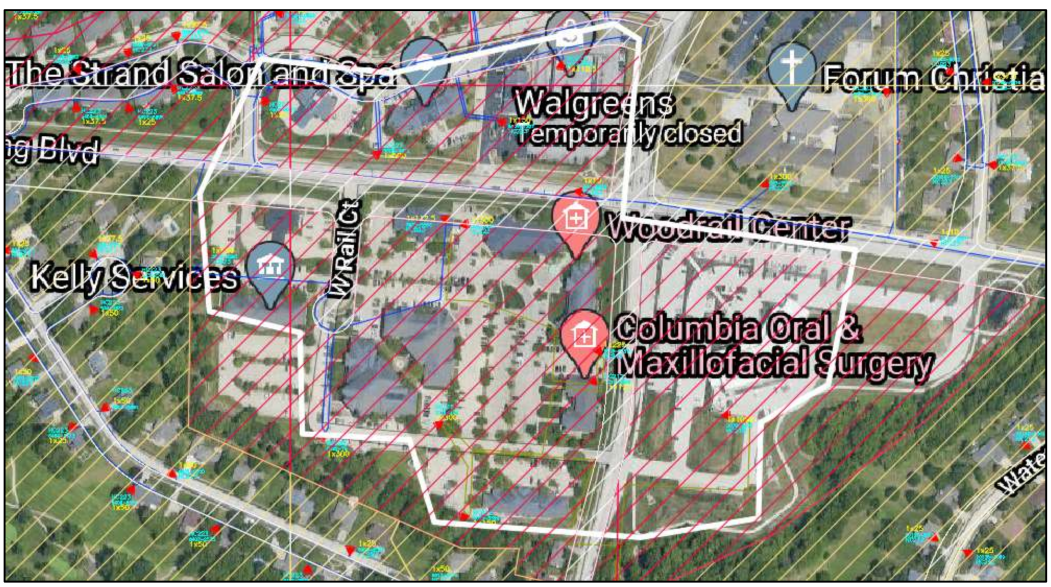
The Second is done by calculating the ratio of the demand of largest consumers of each zoning type by the area (million sqft.) where this power is consumed.

Figure 3-9 below shows an example where the index calculated is for the zoning "PD" (Planed Development, reserved for different activities with a project approved), in the area studied there is a bank, a drugstore, a dental clinic and others stores, the division on the load by the area the resulting index is 1847.81 kVA for million sqft., 2000 was used after averaging with other similar locations and rounding up.

In general, fully occupied Zones like the one below are selected to determine various preliminary Load Indices that are then averaged to produce the final.

These indices allow us to establish a top or "maximum load possible according to zoning type", multiplying the amount of area of each type of zoning and summing all the areas.

Figure 3-9 Image of a location used for taking the Load Index



Dividing the current cell's load by this possible maximum load an "electric saturation" value is obtained, which indicates how loaded a certain cell is according to possibility of the current zonings. When allocating the spatial forecast these concepts will come extremely useful as the whole allocation depends on the potential to growth and this is very dependent on cell saturation.

Figure 3-10 below shows a partial view of the calculation of the max load according to index and the saturation obtained.

Figure 3-10 Excel File with maximum possible load per cell and Electric Saturation %

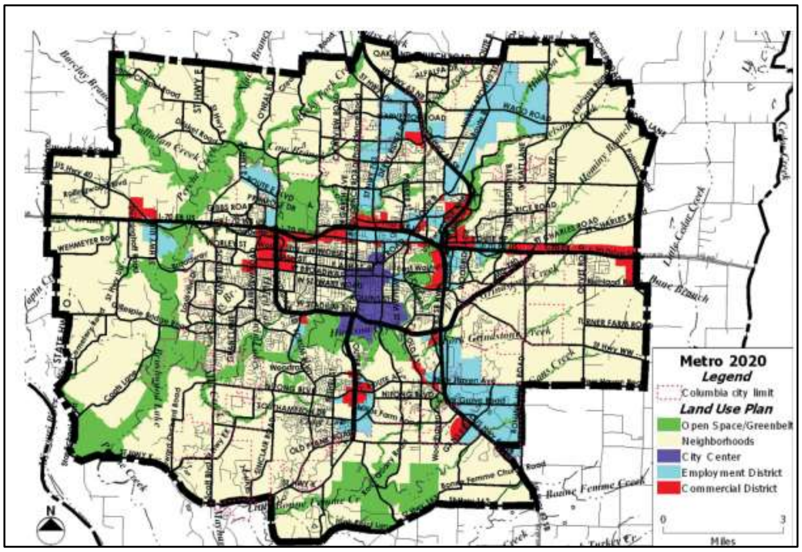
=(D1339*D1+E1339*E1+F1339*F1+G1339*G1+H1339*H1+I1339*I1+J1339*J1+K1339*K1+L1339*L1+M1339*M1+N1339*N1+O1339*O1+P1339*P1+Q1339*Q1+R1339*R1)/1000000

	K	L	M	N	O	P	Q	R	T	U	V	W
800	500	3000	2500	6000	5000	4000	1000	200				
	R-2	M-OF	M-C	IG	M-BP	M-DT	C-2	Other		Calc. Max. Load	Real Load	Calc. Sat.
0	0	0	0	0	0	0	0	3584000	AAU	716.8	0	0%
203.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	562223.14	CGH	4740.148959	374.3514138	8%
80.582	91258.31301	0	0	0	0	0	0	60844.1365	CGI	1014.126773	81.5661854	8%
0	0	0	375251.4372	0	0	0	0	316962.7685	CGJ	5133.166583	3044.154486	59%
5.7271	0	0	1321888.445	0	0	0	0	652188.7589	DGF	5669.650797	2375.85007	42%
01.968	274139.6334	0	1718778.143	0	0	0	0	811652.765	DGG	5059.07448	1391.162456	27%
0	652169.1046	17346.0546	1187973.087	120299.7158	0	0	0	1011055.77	DGH	4832.339017	1248.369395	26%
2.5361	1257024.066	9019.277918	1100186.104	278200.8511	0	0	0	639474.4831	DGI	5510.163028	1663.958176	30%
20.929	753874.1342	0	1037556.501	316690.3118	0	0	0	808955.4233	DGJ	5973.837535	1529.504173	26%
6.6727	780870.9199	0	811302.9767	1162210.967	0	0	0	403430.6936	EGF	=(D1339*D1+E1339*E1+F1339*F1-		
999.14	0	53106.10737	950672.9036	375518.3866	0	0	0	658240.1095	EGG	G1339*G1+H1339*H1+I1339*I1+		

3.6 Location and ranking areas with Load Growth possibilities

To allocate the load growth, there are some general rules over where to expect a higher development or demand growth. These rules include proximity to the main roads or to other loads as is the case of the downtown. However, the comprehensive development plans, transportation plan and other city-made guidelines for the development would have a higher weight on the load allocation. However, as the Columbia plans does not have these plans, and there is plenty space left in the metro area, the procedure for the allocation was modified. In this case, higher importance was given to cells with empty lots near to the developed areas and to neighborhoods already being developed. Figure below shows the future land use.

Figure 3-11 Columbia City Development Plan 2020



To establish the potential growth of the cells, a detailed inspection via Google satellite images was performed on each one of the cells. The figure below shows in a partial view the items evaluated in the inspection from the review of the satellite images. There are deterministic but approximate values as the Used Terrain that represent the amount of land already taken, there are some qualitative items like the development level and chances to grow and there are exact deterministic factors as is the CWL territory in cell that is obtained with the GIS data.

Figure 3-12 Columbia City Development Plan 2020

	Used Terrain (%)	CWL Territory in Cell(%)	Development Level (1 to 5)	Chaces to Grow (1 to 5)	Electric Saturation (%)	Max Load According to Indexes (kVA)	Power Factor
FJG	5.00	28.00	1.00	3.00	0.02	910.01	0.99
FJH	10.00	27.00	1.00	3.00	0.04	891.29	0.99
FJL	5.00	98.00	1.00	1.00	0.02	1492.68	0.95
FJM	15.00	99.00	1.00	2.00	0.03	1161.14	0.99
FJR	15.00	97.00	1.00	1.00	0.04	6380.33	0.85
FJS	50.00	96.00	3.00	2.00	0.19	13709.13	0.85
FJV	75.00	94.00	2.00	1.00	0.13	2163.28	0.99
FJX	50.00	92.00	3.00	5.00	0.03	10099.43	0.85

Figure 3-13 Samples of Factor to Potential Growth shows an example of the application of these concepts. The figure shows images of two very different cells: Cell FIJ is completely in the CWL territory and no land is being used, therefore the development level is 1 and used terrain is 0 (agricultural land is not considered when the electric saturation is 0), and as the roads are also far from this area; the chances to grow is also 1.

The FIQ in contrast, is not completely in CWL territory, most of the terrain is already in use (rounded up to 70%) and there are residential parks and large industrial buildings, as this is not one of the denser areas a subjective development level of 3 was assigned, and as the main road goes across and there is still land to be used a 4 (high) chance to grow was given.

Figure 3-13 Samples of Factor to Potential Growth

	Used Terrain (%)	CWL Territory in Cell(%)	Development Level (1 to 5)	Chaces to Grow (1 to 5)	Electric Saturation (%)
FIH	75.00	99.00	3.00	3.00	0.07
FII	20.00	99.00	4.00	1.00	0.41
FIJ	0.00	99.00	1.00	1.00	0.00
FIK	0.00	98.00	1.00	1.00	0.04
FIL	70.00	95.00	2.00	2.00	0.02
FIM	80.00	99.00	1.00	3.00	0.00
FIN	0.00	99.00	1.00	1.00	0.00
FIO	0.00	98.00	1.00	1.00	0.00
FIP	10.00	94.00	1.00	1.00	0.00
FIQ	70.00	93.00	3.00	4.00	0.03
FIR	30.00	98.00	3.00	1.00	0.00

Chances to growth was also used as a discriminator on when to apply the growth to a specific cell: for 2025 only cells with 4 or 5 ratings were given growth; for 2030 only those 3 or higher; and for 2040 2 or higher (the cells with rating 1 was never given any growth due the low chances that load will appear there). This way we would be modeling the probabilities of the spatial and temporary allocation of the growth. The cell data and factors were placed in the "Zoning index – Spatial Transformers Load Allocation.xlsx", and a partial view of the calculations, show in the Figure 3-14 below.

Figure 3-14 Partial view of the Calculation in Excel

Chaces to Grow (1 to 5)	Electric Saturation (%)	Max Load According to Indexes (kVA)	Power Factor	Cell Load 2020 Forecast (kW)	Potential to grow 2025 (% of max load)	2025 Gross kW to add	2025 Adjusted Growth (% of max Load to add)	Potential to grow 2030 (% of max load)	2030 Gross kW to add
2.00	0.24	2387.00	0.97	584.11	0.00	0.00	0.00	0.00	0.00
1.00	0.17	1737.97	0.97	292.29	0.00	0.00	0.00	0.00	0.00
5.00	0.21	4514.09	0.86	965.03	15.04	678.92	1.80	15.04	678.92
1.00	1.27	7523.59	0.86	9555.48	0.00	0.00	0.00	0.00	0.00
4.00	0.50	6576.72	0.88	3273.28	18.48	1215.38	2.21	18.48	1215.38
4.00	1.64	4220.25	0.85	6905.92	50.40	2127.00	6.03	50.40	2127.00
1.00	0.11	1640.83	0.92	185.29	0.00	0.00	0.00	0.00	0.00
1.00	0.49	5406.64	0.85	2626.18	0.00	0.00	0.00	0.00	0.00
2.00	0.32	2515.62	0.87	805.30	0.00	0.00	0.00	0.00	0.00
2.00	0.23	2381.00	0.99	539.17	0.00	0.00	0.00	0.00	0.00

The potential to grow by year for each cell is a weighted factor that considers the land available to build in CWL territory, the chances to grow and development level. This factor represents the percentage of the maximum load that can be developed in each cell to be added to the current electric load of each cell.

However, when summing this potential to growth (converted to MW) the result could be larger than the total system load to be added for the year. So, a target or limit for each year needs to be applied to all cells to prevent the overshooting of the total load. Also, because the EE is assumed to mostly affect the current load, another factor is needed to reduce the that load as well. The Table 3-4 shows the forecasted new load to be allocated and the existing load adjustment ratio, that consider on one hand the 0.6% vegetative growth for residential demand and the EE reductions for all the total demand.

Table 3-4: Energy Efficiency and New Load

	Existing Load no EV			Adjustments								
Year	C&I	Residential	Total	Resdential Vegetative Growth	Less EE	Aditional EV Load Industrial (MW)	Aditional EV Load Residential (MW)	Adjusted Existing Load with EV	New Load (MW)	Total Load with EV (MW)	Adjusting Load Ratio	Existing Load Ratio
2020	158	117	274.6	-	(1.6)	0.052444775	0.044451176	273.09	-	273.09		
2021	158	117	274.6	0.7	(3.3)							
2022	158	117	274.6	1.4	(4.9)							
2023	158	117	274.6	2.1	(6.6)							
2024	158	117	274.6	2.8	(8.2)							
2025	158	117	274.6	3.6	(9.9)	0.213479136	0.180940784	268.65	7.58	276.23	98%	0.98
2026	158	117	274.6	4.3	(11.6)							
2027	158	117	274.6	5.0	(13.3)							
2028	158	117	274.6	5.7	(15.0)							
2029	158	117	274.6	6.5	(16.8)					-		
2030	158	117	274.6	7.2	(16.9)	0.585305293	0.496093438	266.05	15.05	281.10	96%	0.974210838
2031	158	117	274.6	8.0	(17.0)							
2032	158	117	274.6	8.7	(17.1)							
2033	158	117	274.6	9.5	(17.2)							
2034	158	117	274.6	10.2	(17.3)							
2035	158	117	274.6	11.0	(17.4)							
2036	158	117	274.6	11.8	(17.6)							
2037	158	117	274.6	12.5	(17.7)							
2038	158	117	274.6	13.3	(17.8)							
2039	158	117	274.6	14.1	(17.9)							
2040	158	117	274.6	14.9	(18.0)	1.747851906	1.481445446	274.67	29.94	304.61	98%	1.005794261

Figure 3-15 Forecast Matching

Year	Forecasted Demand (MW)	Existing Load Ratio	New Load (MW)	Calculated New Load (MW)	Adjustment Factor
2020	273.09				
2025	276.23	0.98	7.58	35.143	0.21568
2030	281.10	0.96	15.05	123.188	0.12218
2040	304.61	0.98	29.94	169.800	0.17632

Match

	Load 2020 (kW)	Load 2025 (kW)	Load 2030 (kW)	Load 2040 (kW)
FDL	17.22	524.27	792.35	1188.99
FDP	7.12	51.36	74.60	109.16
FDU	8.98	8.84	8.51	8.32
ACD	71.78	70.61	68.01	66.46
ACI	43.74	43.03	41.44	40.49
BCF	9.26	9.11	8.78	8.57
BCK	81.26	79.94	76.99	75.23
BCL	21.33	20.98	20.21	19.75
BCU	24.70	24.30	23.40	22.87
BCX	103.43	101.74	97.99	95.75
BBA	70.31	69.16	66.61	65.09
BBG	0.01	0.01	0.01	0.01
Totals	273.09	276.23	281.10	304.61

Figure 3-15 shows the two factors applied to the existing load and the new load to match the forecasted growth. Once the future load by cell matches the forecast, the same grow ratio is applied to the load connected on to the transformer contained in each cell allocating it to the system model. Figure 3-16 shows two partial views of the percentage growth by cell and the transformer growth based on that cell growth.

Figure 3-16 Transformer Growth

	Growth 2025/2020	Growth 2030/2025	Growth 2040/2030
EDO	136%	29%	35%
EDT	-2%	-4%	-2%
EDZ	-2%	-4%	-2%
FDA	53%	16%	23%
FDF	-2%	30%	35%
FDG	90%	24%	30%
FDK	288%	39%	42%
FDL	2945%	51%	50%
FDP	622%	45%	46%

TL	CAPACITY	KW	KVAR	CELL	2025 kW	2025 kVAr	2030 kW	2030 kVAr	2040 kW	2040 kVAr
595	1x37.5	6.599752403	0.940413784	DGL	6.49	0.93	6.25	0.89	6.11	0.87
596	1x50	19.51330607	4.890495489	DGL	19.20	4.81	18.49	4.63	18.07	4.53
597	1x112.5	32.03225252	19.85180715	EGD	31.51	19.53	32.96	20.43	35.98	22.30
598	1x10	7.526769288	4.664672653	DFM	7.40	4.59	11.26	6.98	16.96	10.51
599	1x10	7.053395217	4.371301753	CGR	6.94	4.30	6.68	4.14	6.53	4.05
601	1x15	0.650951817	0.403423703	DGZ	0.64	0.40	0.62	0.38	0.60	0.37
602	1x112.5	76.73296576	47.5548211	DGJ	75.49	46.78	74.42	46.12	75.19	46.60
603	1x75	22.13367801	13.71722164	DGJ	21.77	13.49	21.47	13.30	21.69	13.44
604	1x25	14.93736066	2.128458616	DGJ	14.69	2.09	14.49	2.06	14.64	2.09
605	1x37.5	15.14578895	2.158158039	DGJ	14.90	2.12	14.69	2.09	14.84	2.11
606	1x50	8.29544587	1.182037017	DGJ	8.16	1.16	8.05	1.15	8.13	1.16
607	1x15	2.537969198	1.572892042	DGE	2.50	1.55	2.40	1.49	2.46	1.52
608	1x50	40.26834528	14.6154577	DGJ	39.61	14.38	39.05	14.17	39.46	14.32

At this point we have the transformer load for all the years of study and the final step is to confirm the accuracy of the results in the model. Below there are two examples of the resulting spatial allocation and checks performed.

Figure 3-17 Example 1 – Little chance to Load Growth

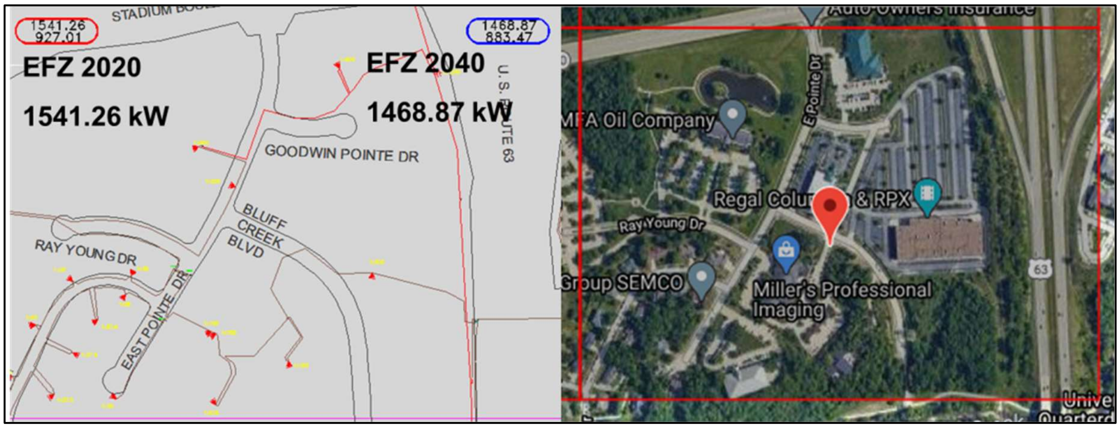
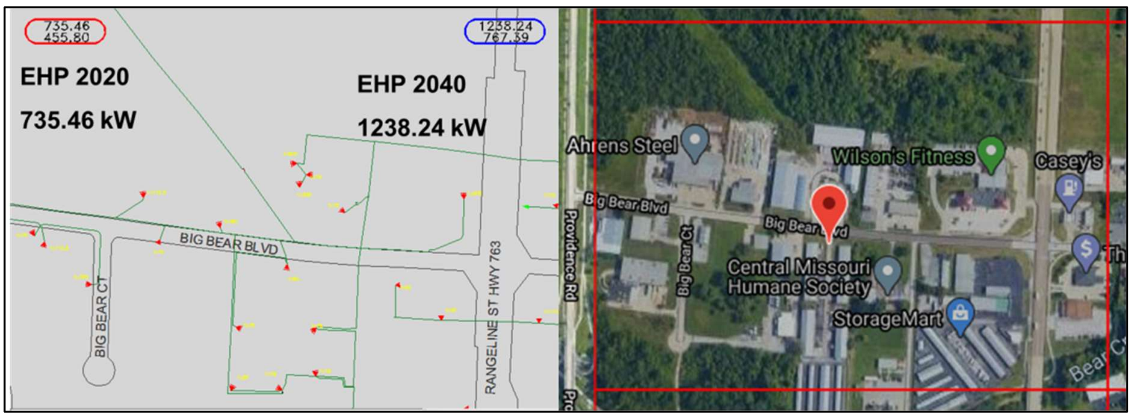


Figure 3-18 Example 2 – High chance to Load Growth



In Figure 3-17, most of the land is already in use or it is within the territory of the University, therefore limited to no new loads were expected for this cell and indeed we see that there is a reduction in load due to EE (the red oval shows the current load 1,541 kW and the blue the future 1,469 kW).

On the other hand, Figure 3-18 is an industrial area with some land to develop and close to the Downtown and to a main road, therefore we can observe that this cell is expected to experience a demand growth (735 kW current to 1,238 kW by 2040).

3.7 Spatial Load Forecast Results

In general, we observed higher growth to the east of downtown and a developing of the northeast of the City towards Bolstad. We observed little change on the south and west. Figure 3-19 shows the heat map of the spatial forecast load allocation were we note that from 2019 to 2040 there an slight but noticeable increase in the load density northeast of the City and the load centers shift in that direction. The load center is a geographical point that is load-weighted equidistant to all loads.

Figure 3-19 Load Heat Map and CWL territory Load Center

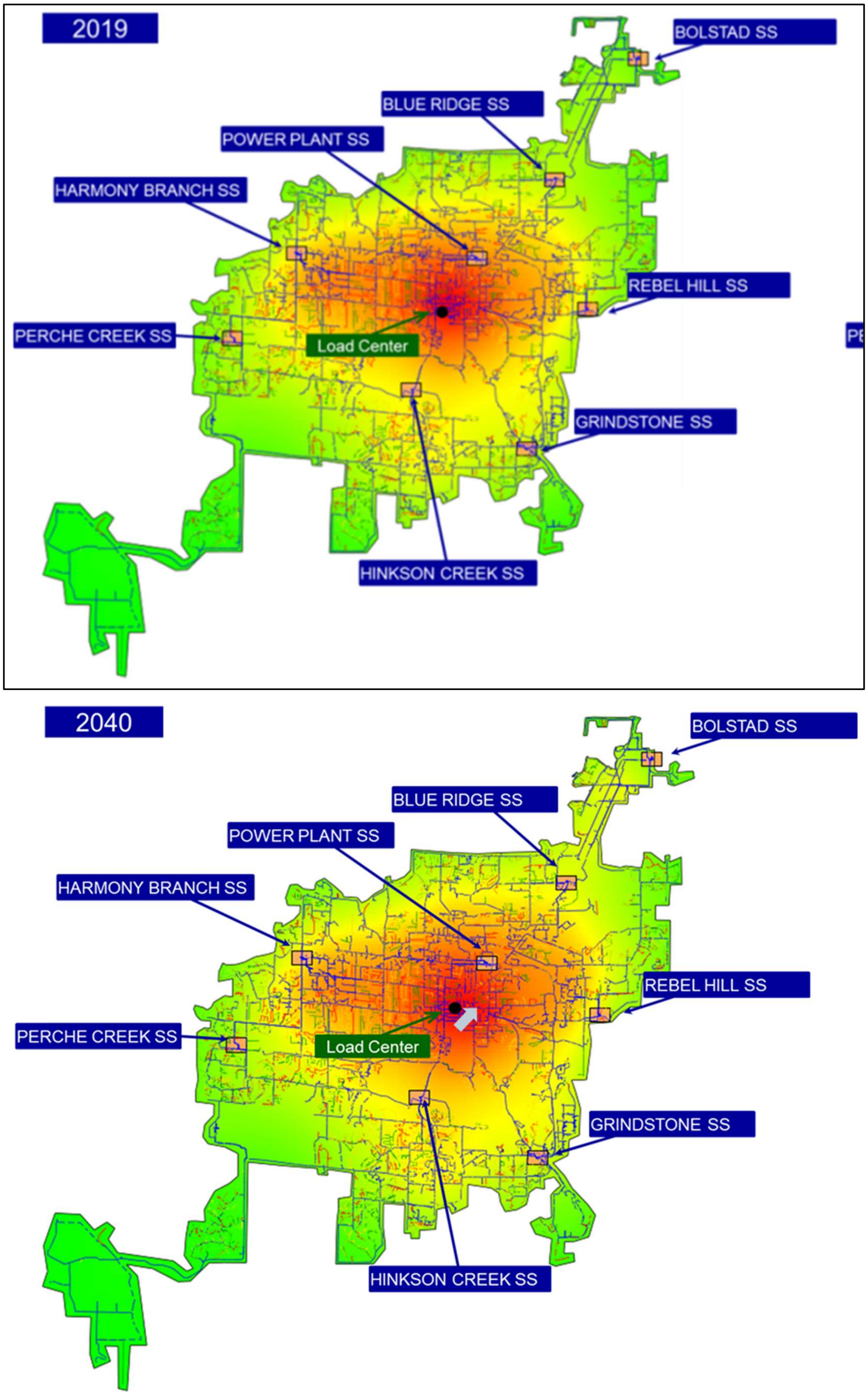


Table 3-5 shows for each substation the forecasted future load at system's peak before any changes in the coverage areas. We observe that Bolstad in the northeast is expected to experience the highest growth, followed by Blue Ridge also in the northeast, Grindstone in the southeast and Revel Hill in the east. The lowest growth is forecasted to happen to the west at Harmony Branch and Perche Creek to the southwest.

Table 3-5: Substation Peak Load (MW) before changes in coverage areas

Substation	2020	2025	2030	2040	Change 2040/2020
Blue Ridge	23.80	23.91	24.98	27.94	117%
Bolstad	14.26	16.20	19.10	25.32	178%
Grindstone	34.90	36.79	37.54	40.87	117%
Harmony Branch	40.47	40.12	39.61	40.98	101%
Hinckson Creek	45.01	44.37	44.74	47.30	105%
Perche Creek	35.03	35.03	34.36	35.43	101%
Power Plant	47.55	47.29	47.63	50.74	107%
Rebel Hill	31.73	32.52	33.14	36.03	114%
Total	**273**	**276**	**281**	**305**	**112%**

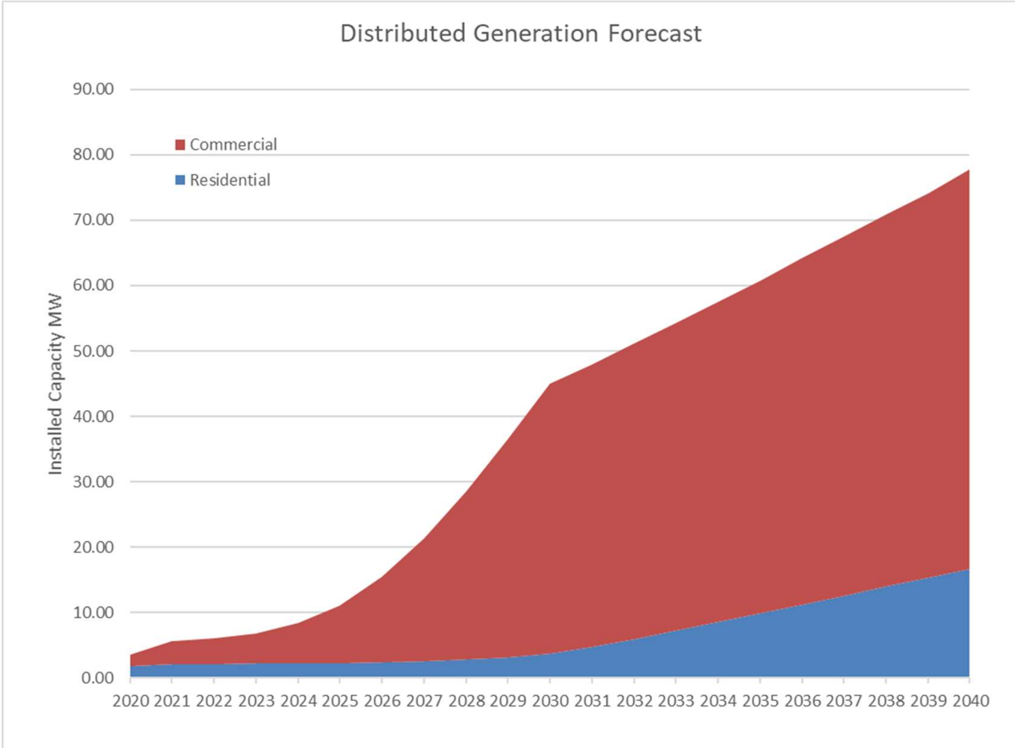
3.8 Spatial Allocation of Distributed Generation

Distributed generation consists mainly of solar panels (PVs) and in Volume 1 Section 3.5 Distributed Solar, the methodology and the forecast by residential and Commercial customers. Figure 3-20 shows the overall forecast and Table 3-6 shows the actual values allocated for 2025, 2030 and 2040 used for the assessment of the system, in addition to the current 2020 values.

Table 3-6: Forecasted distributed generation between 2020 and 2040

	Residential MW	Commercial MW	Total MW
2020	1.73	1.78	3.5
2025	2.24	8.80	11.0
2030	3.62	41.38	45.0
2040	16.68	61.09	77.8

Figure 3-20: Forecasted Distributed Generation



This forecast is aggregated and does not indicates where this new generation is likely to be located, thus we developed a method for its allocation to the network. The basic criterion is that the larger consumers are more likely to install the PV arrays first. Therefore, we assigned the distributed generation considering the customers consumption for each year.

To do this, we first ranked the top consumers for the Residential and Commercial and added to this last group the Industrial and Others (CIO). These consumers are associated with an account number, which is also associated with the transformer location number. In the model all these customers would be represented only by its transformer location. Table below is a partial view of this ranking for the CIO customers.

Table 3-7: Commercial Industrial and Other Customer Ranking (partial view)

Account	XFMR Location Account	Final Calc kW	Final Calc kVAr	Final Calc kVA	Cutomer Type	Feeder
29888	9149	5,778	3,581	6,797	CIO	PP231
59652	3819	5,389	3,340	6,340	CIO	BD213
59606	7581	2,794	1,732	3,287	CIO	BD213
45208	4831	2,069	1,282	2,434	CIO	RH221
73960	3987	1,645	1,020	1,936	CIO	HB233
11392	11081	1,355	840	1,594	CIO	PC221
59674	2000	1,351	838	1,590	CIO	BD211
73536	4913	1,123	696	1,321	CIO	HB233
33548	6389	1,003	622	1,180	CIO	GS211
76610	11011	977	605	1,149	CIO	PC221
42314	4773	919	570	1,081	CIO	GS212
159288	8623	860	533	1,012	CIO	PC222
32918	4523	834	517	981	CIO	HC231
47890	431	830	515	977	CIO	RH222
159286	10235	801	496	942	CIO	HB233
140308	10259	784	486	922	CIO	GS233
121900	1305	770	477	906	CIO	HB222
74000	4081	764	473	898	CIO	HB212
159306	5694	754	468	888	CIO	RH211
59678	1474	751	466	884	CIO	BD223

Next, and in line with the distributed generation forecast we assumed typical sizes for residential installations (7.6 kW) and for commercial installations (31.2 kW). For this last group we initially considered increasing the size of the PV for larger commercial customers, but the impact was small and in this way the allocation was consistent with the forecast that was based on participants and uniform installation sizes.

The tables below show a partial view of the allocation by residential and COI customers.

Table 3-8: Distributed Generation Allocation for Residential Customer (partial view)

		2025 Participants	292	2030 Participants	471	2040 Participants	2,168
		2025 Target KW	2,242	2030 Target KW	3,621	2040 Target KW	16,679
Account	Feeder	Allocated to Customer (KW)	Balance to Allocate (KW)	Allocated to Customer (KW)	Balance to Allocate (KW)	Allocated to Customer (KW)	Balance to Allocate (KW)
73700	HB213	7.60	2,235	7.60	3,613	7.60	16,672
25600	HC233	7.60	2,227	7.60	3,606	7.60	16,664
25598	RH212	7.60	2,219	7.60	3,598	7.60	16,657
25472	HC233	7.60	2,212	7.60	3,590	7.60	16,649
27118	PP232	7.60	2,204	7.60	3,583	7.60	16,641
166602	GS231	7.60	2,197	7.60	3,575	7.60	16,634
18344	HC213	7.60	2,189	7.60	3,568	7.60	16,626
162642	GS231	7.60	2,181	7.60	3,560	7.60	16,619
20710	HC223	7.60	2,174	7.60	3,552	7.60	16,611
143246	HC223	7.60	2,166	7.60	3,545	7.60	16,603
26964	PP221	7.60	2,159	7.60	3,537	7.60	16,596
162814	GS231	7.60	2,151	7.60	3,530	7.60	16,588
163004	GS231	7.60	2,143	7.60	3,522	7.60	16,581
112824	BR211	7.60	2,136	7.60	3,514	7.60	16,573
121758	GS213	7.60	2,128	7.60	3,507	7.60	16,565
115908	HC223	7.60	2,121	7.60	3,499	7.60	16,558
43060	GS212	7.60	2,113	7.60	3,492	7.60	16,550
41034	GS213	7.60	2,105	7.60	3,484	7.60	16,543
150560	GS231	7.60	2,098	7.60	3,476	7.60	16,535
30984	GS232	7.60	2,090	7.60	3,469	7.60	16,527
162894	GS231	7.60	2,083	7.60	3,461	7.60	16,520

Table 3-9: Distributed Generation Allocation for Commercial Industrial and Other Customer (partial view)

		2025 Participants	282	2030 Participants	1,327	2040 Participants	1,955
		2025 Target KW	8,801	2030 Target KW	41,378	2040 Target KW	61,093
Account	Feeder	Allocated to Customer (KW)	Balance to Allocate (KW)	Allocated to Customer (KW)	Balance to Allocate (KW)	Allocated to Customer (KW)	Balance to Allocate (KW)
29888	PP231	31.20	8,770	31.20	41,347	31.20	61,062
59652	BD213	31.20	8,739	31.20	41,316	31.20	61,031
59606	BD213	31.20	8,707	31.20	41,285	31.20	61,000
45208	RH221	31.20	8,676	31.20	41,253	31.20	60,969
73960	HB233	31.20	8,645	31.20	41,222	31.20	60,937
11392	PC221	31.20	8,614	31.20	41,191	31.20	60,906
59674	BD211	31.20	8,583	31.20	41,160	31.20	60,875
73536	HB233	31.20	8,551	31.20	41,129	31.20	60,844
33548	GS211	31.20	8,520	31.20	41,097	31.20	60,813
76610	PC221	31.20	8,489	31.20	41,066	31.20	60,781
42314	GS212	31.20	8,458	31.20	41,035	31.20	60,750
159288	PC222	31.20	8,427	31.20	41,004	31.20	60,719
32918	HC231	31.20	8,395	31.20	40,973	31.20	60,688
47890	RH222	31.20	8,364	31.20	40,941	31.20	60,657
159286	HB233	31.20	8,333	31.20	40,910	31.20	60,625
140308	GS233	31.20	8,302	31.20	40,879	31.20	60,594
121900	HB222	31.20	8,271	31.20	40,848	31.20	60,563
74000	HB212	31.20	8,239	31.20	40,817	31.20	60,532
159306	RH211	31.20	8,208	31.20	40,785	31.20	60,501
59678	BD223	31.20	8,177	31.20	40,754	31.20	60,469
49778	PP223	31.20	8,146	31.20	40,723	31.20	60,438
59602	BD222	31.20	8,115	31.20	40,692	31.20	60,407
159312	BR211	31.20	8,083	31.20	40,661	31.20	60,376
148640	RH211	31.20	8,052	31.20	40,629	31.20	60,345
37444	HC211	31.20	8,021	31.20	40,598	31.20	60,313

With this assignment, we summarized the values by feeder and confirmed that the geographically allocated values of distributed generation matched the targets in Table 3-6. This is shown in the table below (partial view), where we note that there is a small mismatch, but it is smaller than selected installation size per customer, thus is due to not having "partial" installations.

Table 3-10: Distributed Generation Allocation by Feeder (partial view)

	Residential and Commercial			Residential Only			Commercial Only		
Target	11,043	44,999	77,773	2,242	3,621	16,679	8,801	41,378	61,093
Allocated Total	11,040	44,989	77,764	2,242	3,618	16,674	8,798	41,371	61,090
Mismatch	3	10	9	0	3	5	3	7	4
Feeder ID	2025(kW)	2030(kW)	2040(kW)	2025(kW)	2030(kW)	2040(kW)	2025(kW)	2030(kW)	2040(kW)
BD211	31.2	62.4	62.4	0.0	0.0	0.0	31.2	62.4	62.4
BD212	0.0	249.6	288.4	0.0	0.0	7.6	0.0	249.6	280.8
BD213	62.4	156.0	218.4	0.0	0.0	0.0	62.4	156.0	218.4
BD221	31.2	124.8	124.8	0.0	0.0	0.0	31.2	124.8	124.8
BD222	62.4	93.6	171.2	0.0	0.0	15.2	62.4	93.6	156.0
BD223	62.4	405.6	561.6	0.0	0.0	0.0	62.4	405.6	561.6
BR211	162.8	598.8	1,502.0	38.0	68.4	722.0	124.8	530.4	780.0
BR212	77.6	630.8	1,663.6	15.2	38.0	509.2	62.4	592.8	1,154.4
BR213	499.2	1,092.0	1,474.0	0.0	0.0	7.6	499.2	1,092.0	1,466.4
BR221	46.4	54.0	266.8	15.2	22.8	235.6	31.2	31.2	31.2
BR222	369.6	2,067.2	3,646.0	182.4	288.8	1,056.4	187.2	1,778.4	2,589.6
GS211	226.0	1,130.8	1,487.6	7.6	7.6	83.6	218.4	1,123.2	1,404.0
GS212	272.4	669.6	1,122.8	22.8	45.6	311.6	249.6	624.0	811.2
GS213	108.0	232.8	477.6	45.6	45.6	228.0	62.4	187.2	249.6
GS221	62.4	93.6	93.6	0.0	0.0	0.0	62.4	93.6	93.6
GS222	280.8	1,092.0	1,520.4	0.0	0.0	22.8	280.8	1,092.0	1,497.6
GS223	194.8	202.4	217.6	7.6	15.2	30.4	187.2	187.2	187.2
GS231	767.6	1,087.6	2,509.6	767.6	1,056.4	2,447.2	0.0	31.2	62.4
GS232	240.4	918.4	1,846.4	53.2	76.0	380.0	187.2	842.4	1,466.4
GS233	62.4	475.6	691.6	0.0	7.6	98.8	62.4	468.0	592.8
HB211	93.6	374.4	753.2	0.0	0.0	129.2	93.6	374.4	624.0
HB212	187.2	530.4	655.2	0.0	0.0	0.0	187.2	530.4	655.2
HB213	506.8	1,700.0	2,432.8	7.6	15.2	30.4	499.2	1,684.8	2,402.4
HB221	194.8	529.6	1,003.2	7.6	30.4	410.4	187.2	499.2	592.8
HB222	155.2	427.6	932.4	30.4	53.2	433.2	124.8	374.4	499.2
HB223	38.0	349.2	945.2	38.0	68.4	539.6	0.0	280.8	405.6
HB231	374.4	561.6	615.6	0.0	0.0	22.8	374.4	561.6	592.8
HB232	156.0	475.6	784.4	0.0	7.6	129.2	156.0	468.0	655.2
HB233	249.6	1,029.6	1,544.0	0.0	0.0	15.2	249.6	1,029.6	1,528.8
HC211	218.4	1,840.8	2,979.2	0.0	0.0	15.2	218.4	1,840.8	2,964.0
HC212	194.8	795.2	1,471.6	7.6	15.2	98.8	187.2	780.0	1,372.8
HC213	313.2	784.8	2,145.6	250.8	410.4	1,459.2	62.4	374.4	686.4

For modeling all the residential PV generation by feeder was reduced to just one equivalent PV array located near the largest consumers in the feeder or at ¾ of feeder length in case that there was not a clearly identifiable location. For commercial customers we located the distributed solar at the same transformer supplying the customer. Figure 3-20 provides an overview of the location of the distributed generation by year.

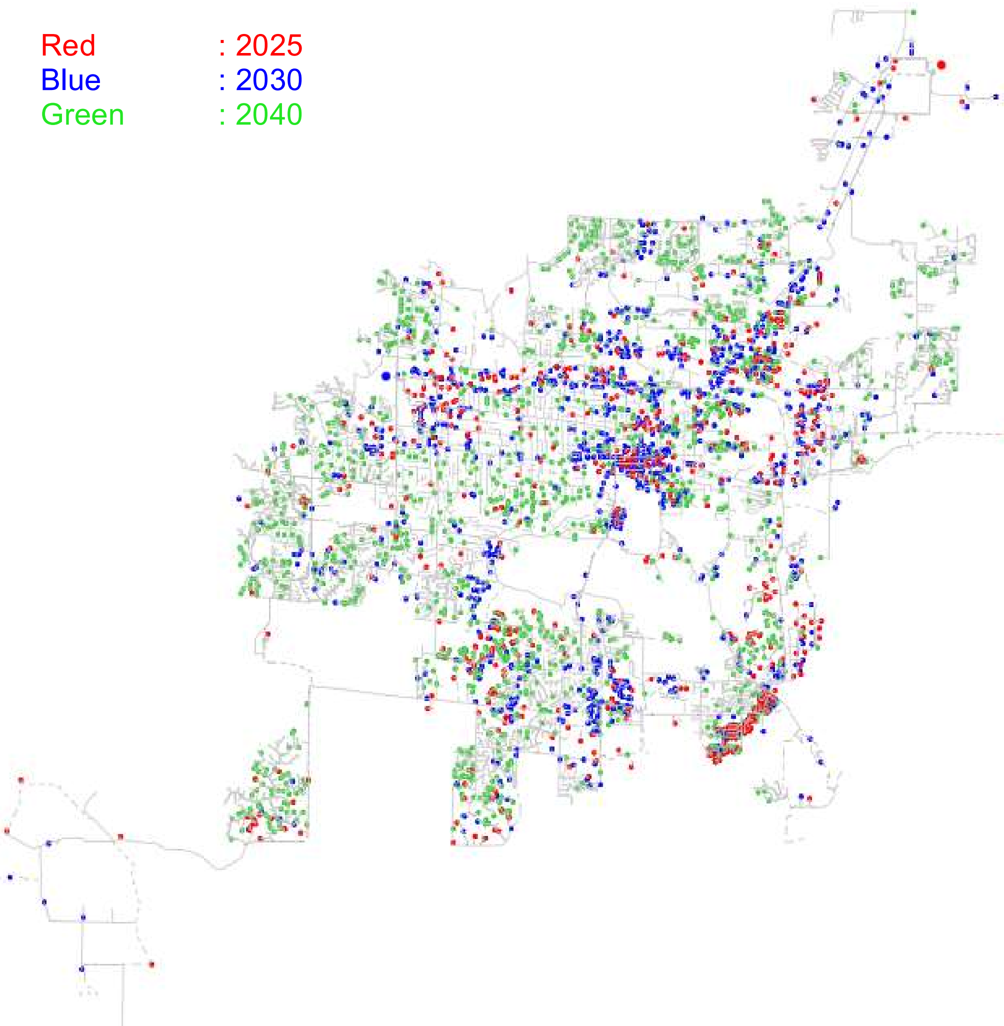


Figure 3-21: Location of forecast PVs between 2025 and 2040

4 Substation Expansion and Coverage Areas

This section presents the analysis of the existing substations' coverage areas and its recommended modification, the need to expand the substations' transformer capacity and the need for new substations.

The analysis was performed for each substation individual peak demand as this is what drives the needs for transformation capacity, rather than its load at the time of the peak. The relation between these two loads is the Coincidence Factor and it was used to convert the loading as modeled for the time of the system peak to the individual substation peaks.

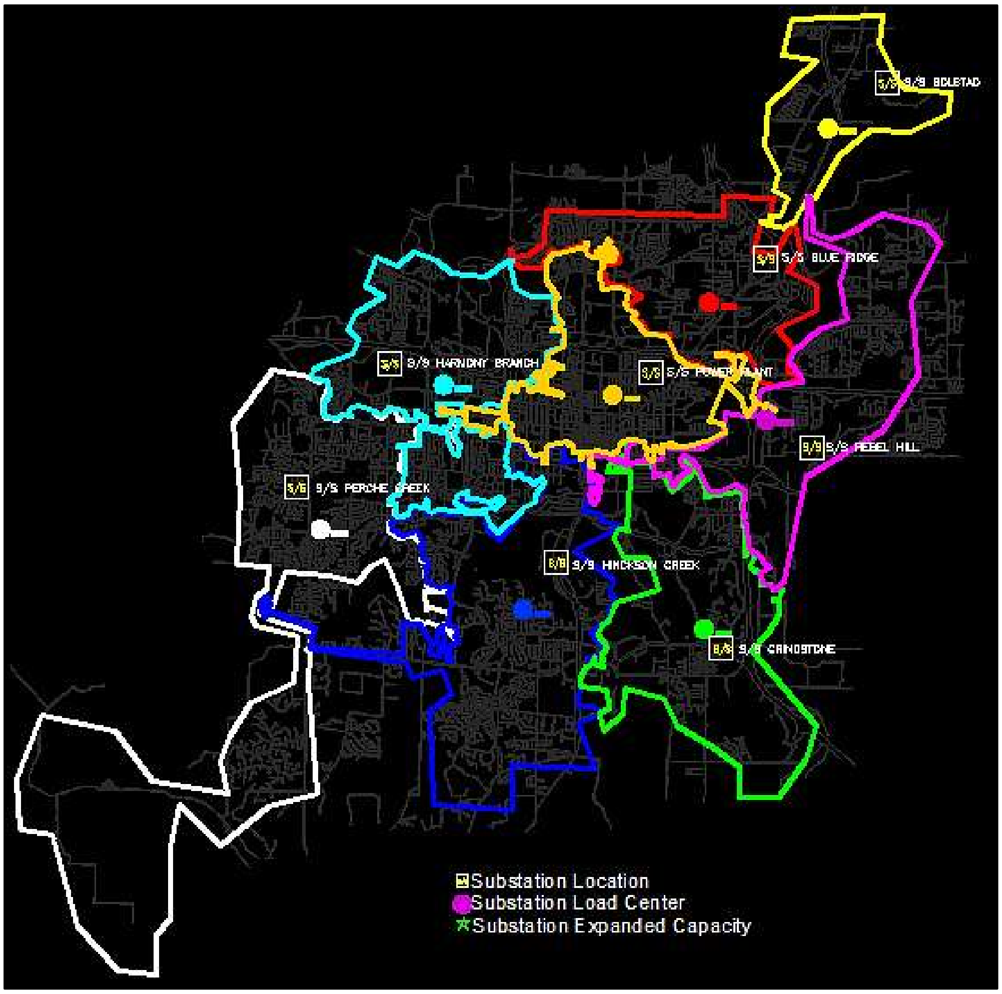
Table 4-1 summarizes these factors and shows the time and date where each substation peak happens, when the factor is unit, it means that the substation's peak coincides with the system's peak. The largest difference is observed at Bolstad that tends to peak much earlier in the day around noon time while the system peak is in the late afternoon. Other differences are due to changes in the day of the peak.

Table 4-1: Substations Coincidence Factors

	Blue Ridge	Bolstad	Grindstone	Harmony .	Hicnkson C.	Perche C.	Power P.	Rebel H.
Substations Max Load	21.97	20.67	38.94	37.75	41.74	32.73	48.11	29.63
Time at Substation Max Load	19/7/2019 16:00	10/7/2019 11:00	30/1/2019 7:00	19/7/2019 16:00	19/7/2019 17:00	12/8/2019 18:00	19/9/2019 15:00	19/7/2019 16:00
SS Load at System Peak time	21.97	12.19	32.57	37.75	41.73	31.82	44.76	29.63
SS max peak/ SS at System Peak	1	1.696089156	1.195558739	1	1.000399441	1.028490625	1.074867804	1

The Coverage Area of the substations is a polygon that encloses all the load supplied by the substation's feeder tying to the distribution transformers. Figure 4-1 shows the current substation coverage area for all the substations. Each substation has a color, and the circle represents the center of the load for the substation (i.e., a point that is load-weighted equidistant to all loads), the small square represents the substation's locations. Ideally the load center and the substation location should coincide as much as possible.

Figure 4-1 Substations Current Coverage Area



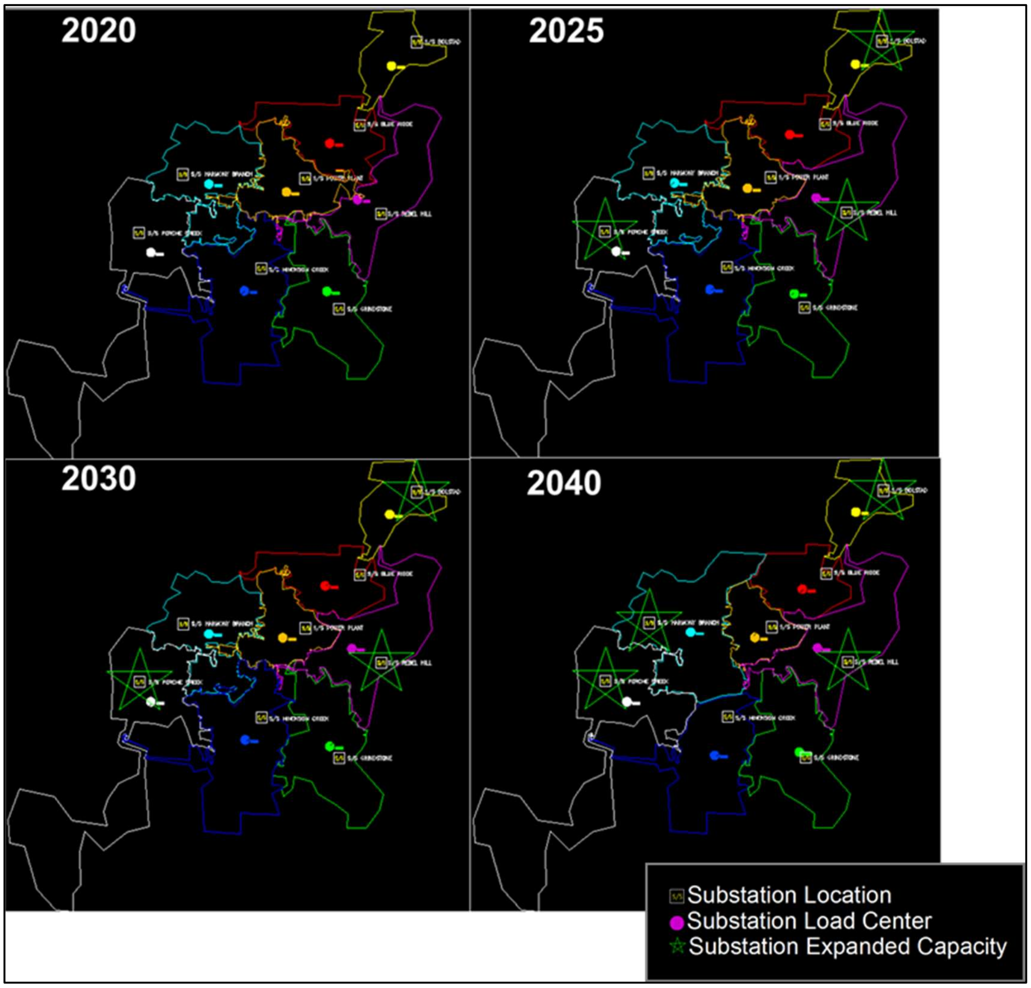
Two proposals were developed:

- Proposal I without a new substation. The new load needs to be feed with an additional capacity and changes in coverage areas.
- Proposal II with a new substation at south, but also needs some expansion and changes in the coverage areas. This affects only Perche Creek and Hinkson Creek

4.1 Proposal I

Figure 4-2 shows an overview on how the increase in load by each term affects the load center of each substation. In this figure a star denotes the substations that would need increases in the installed transformer capacity to maintain 100% redundancy, also known as 100% firm capacity. According to CWL planning criteria in case of one transformer failing at one substation the remaining transformers should be able to supply the load without overloading.

Figure 4-2 Coverage Area Recommended Evolution



As can be observed at multiple substations the load is expected to exceed the installed firm capacity in the next 20 years. This can be addressed by expanding the installed transformer capacity or as not all substations can be expanded, changes in the coverage area are done so the substations that can be expanded take the excess load of those that cannot. Below we provide the details of this redistribution process under the Proposal I, that does not consider new substations and in our opinion would be the preferred. Details are provided by substation.

4.1.1 Bolstad Substation

Bolstad is located at Northeast of the city, LAT: 39.01866160 LON: -92.26046004, at Brundage Rd, the substation transformer capacity needs to be expanded from 2 X 22.4 MVA transformer to 3 X 22.4 MVA as the current load (24.2 MVA) is already over the firm capacity (22.4 MVA). The recommendation is to expand it before 2025. No other changes are expected.

Table 4-2 summarizes the substation's load considering the current coverage area (Forecasted Peak Load), the ratio of peak load to firm capacity that shows the overload, the peak load after changes of the coverage areas (Peak Load After Redistribution), no change for Bolstad, and the new loadings with the new expanded transformer capacity (Peak / New Firm Capacity), that we note that it would address the loading issues noted. Similar tables are provided for all substations.

Figure 4-3 Bolstad Substation

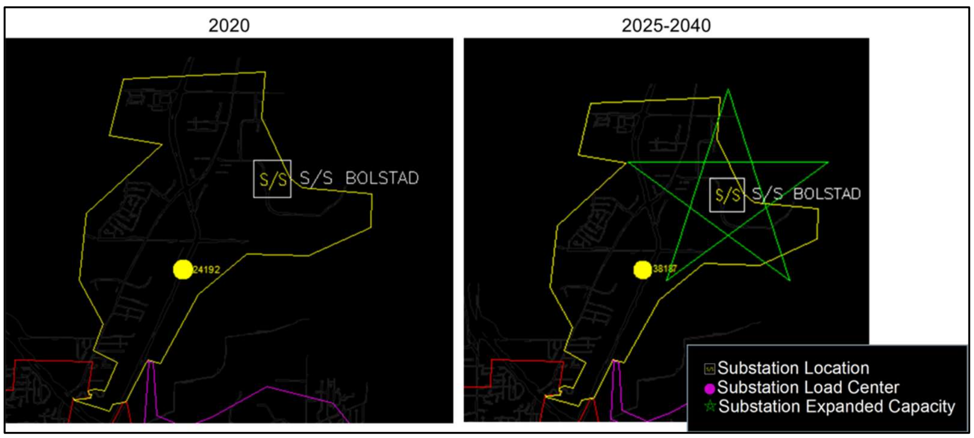


Table 4-2: Bolstad Loading

Bolstad	2020	2025	2030	2040
Forecasted Peak Load [MVA]	24.22	27.47	32.38	43.03
Peak / Firm Capacity (22.4 MVA)	108%	123%	145%	192%
Peak Load After Redistribution [MVA]*		27.47	32.38	42.93
Peak / New Firm Capacity**		61%	72%	96%
*Capacitors installed for PF=1 **New 22.4 MVA transformer added by 2025				

4.1.2 Blue Ridge Substation

Blue Ridge is located on Blue Ridge Rd, at LAT: 38.98560050 LON: -92.28979808. If no changes are carried out, this substation's firm capacity (22.4 MVA) is already exceeded, and the load is expected to reach 112% of the firm capacity by 2040 (see Table 4-3). As there is no physical space to expand this substation, it is recommended that part of load to the southeast to be transferred to Rebel Hill by 2025 and part of the load northwest to be transferred to Harmony Branch by 2040. Figure 4-4 shows the stages of this redistribution and Table 4-3 the peak loads and loading through the years of study.

Figure 4-4 Blue Ridge Substation

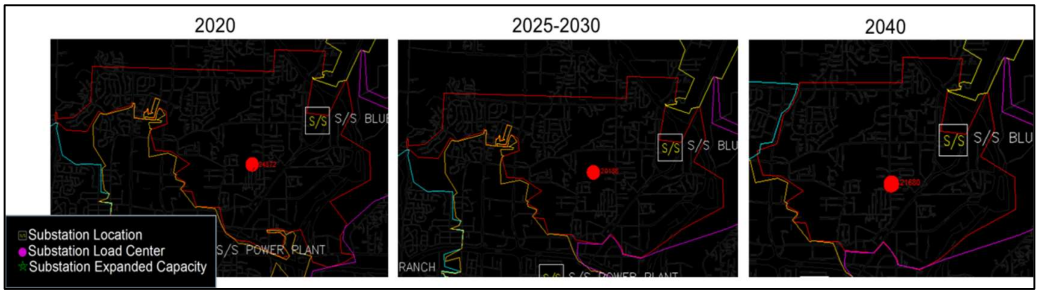


Table 4-3: Blue Ridge Loading

Blue Ridge	2020	2025	2030	2040
Forecasted Peak Load [MVA]	23.84	23.92	24.99	24.99
Peak / Firm Capacity (22.4 MVA)	106%	107%	112%	112%
Peak Load After Redistribution [MVA]*		18.94	19.57	18.28
Peak / New Firm Capacity**		42%	44%	41%
*Capacitors installed for PF=1 **No Expansion Possible				

4.1.3 Grindstone Substation

Grindstone is located on Ponderosa St, at LAT: 38.91231168 LON: -92.30056167. This substation load will exceed its firm capacity (44.8 MVA) by 2040 (see Table 4-4). As there is not space to expand the substation about 2 MW of load to the northwest of Grindstone's coverage area should transferred to Rebel Hill by then, as shown in Figure 4-5.

Table 4-4 summarizes the substation's the peak loads and loading through the years of study.

Figure 4-5 Grindstone Substation

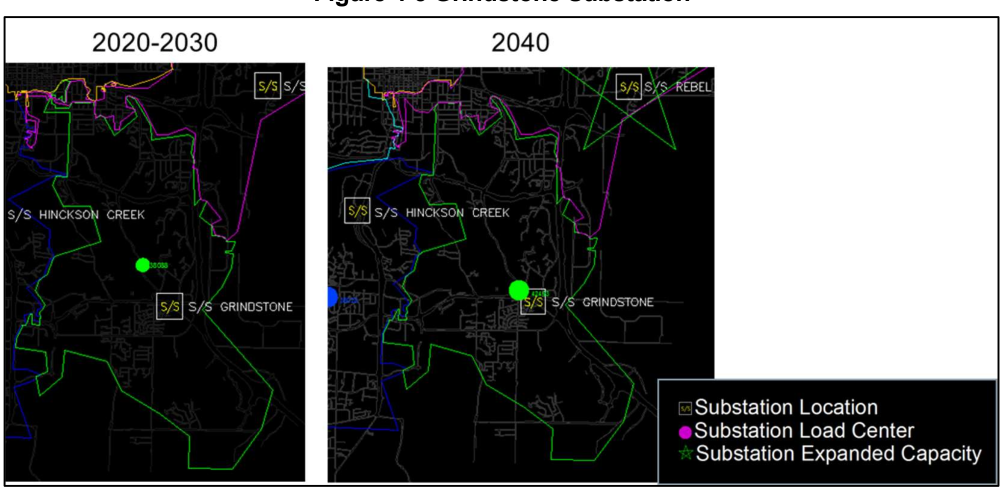


Table 4-4: Grindstone Loading

Grindstone	2020	2025	2030	2040
Forecasted Peak Load [MVA]	41.73	43.94	44.85	48.96
Peak / Firm Capacity (2x22.4 MVA)	93%	98%	100%	109%
Peak Load After Redistribution [MVA]*		43.91	44.80	46.48
Peak / New Firm Capacity**		98%	100%	104%
***Capacitors installed for PF=1**				
****No Expansion Possible**				

4.1.4 Power Plant Substation

Power Plant is Located on Edison St, LAT: 38.96431232 LON: -92.31755903. This substation's firm capacity (44.8 MVA) is already significantly exceeded as shown in Table 4-5. By 2025 the load to the east should be transferred to Rebel Hill and by 2040 part of the load to the west should be transferred to Harmony Branch. Figure 4-6 shows the two steps for the redistribution and Table 4-5 summarizes the substation's peak loads and loading.

Figure 4-6 Power Plant Substation

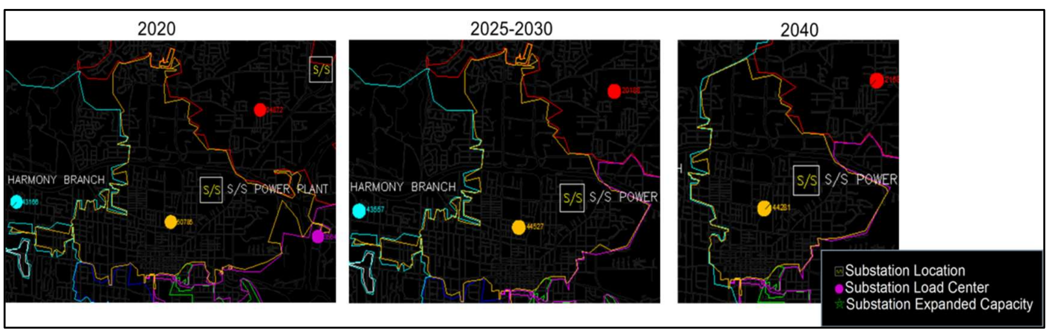


Table 4-5: Power Plant Loading

Power Plant	2020	2025	2030	2040
Forecasted Peak Load [MVA]	51.34	51.03	51.42	54.95
Peak / Firm Capacity (2x22.4 MVA)	115%	114%	115%	123%
Peak Load After Redistribution [MVA]*		44.02	44.41	39.19
Peak / New Firm Capacity**		98%	99%	87%
***Capacitors installed for PF=1**				
****No Expansion**				

4.1.5 Rebel Hill Substation

Rebel Hill is located on Rebel Hill Dr, at LAT: 38.95020489 LON: -92.27877776. This substation's firm capacity (28 MVA) is already exceeded as shown in and a new transformer (28 MVA) is proposed to be added as soon as possible. This expansion will also allow the transferring of load to this substation from Blue Ridge and Power Plant as it is shown in Figure 4-7. By 2040 this substation also will be able to receive load from Grindstone to the west. Table 4-6 summarizes the substation's the peak loads and loading through the years of study.

Figure 4-7 Rebel Hill Substation

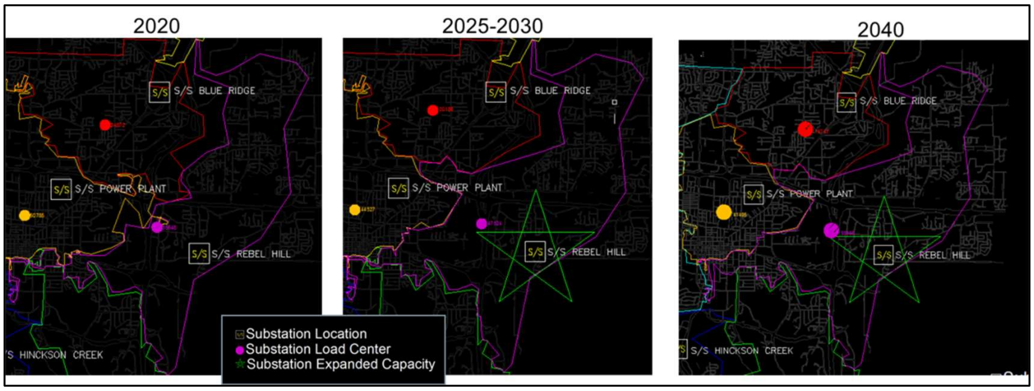


Table 4-6: Rebel Hill Loading

Rebel Hill	2020	2025	2030	2040
Forecasted Peak Load [MVA]	31.72	32.48	33.10	35.96
Peak / Firm Capacity (28 MVA)	113%	116%	118%	128%
Peak Load After Redistribution [MVA]*		43.79	44.83	50.71
Peak / New Firm Capacity**		78%	80%	91%
*Capacitors installed for PF=1 **New 28 MVA transformer added by 2025				

4.1.6 Harmony Branch Substation

Harmony Branch is located on North Fairview Dr., with Bernadette Dr., LAT: 38.96604135 LON: -92.38031450. This substation is not expected to experience any loading issued. However as neighboring substations may become overloaded by 2040, the proposed solution is to expand Harmony branch (from 3x22.4 to 4x22.4 MVA) by then and thus making room for load from Blue Ridge and Power Plant to the northeast and east, and Hinkson Creek to the south to be transferred as shown in Figure 4-8.

Table 4-7 summarizes the substation the peak loads and loading through the years of study.

Figure 4-8 Harmony Branch Substation

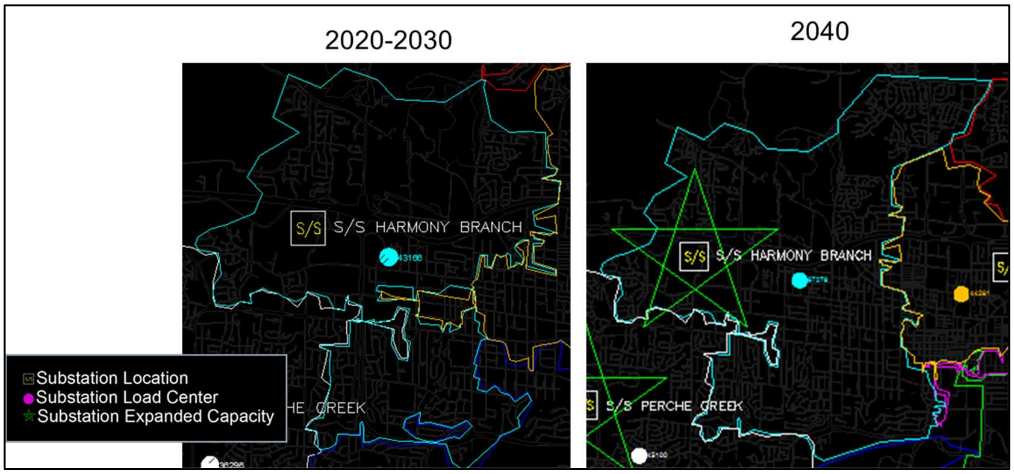


Table 4-7: Harmony Branch Loading

Harmony Branch	2020	2025	2030	2040
Forecasted Peak Load [MVA]	40.55	40.15	39.64	41.01
Peak / Firm Capacity (2x22.4 MVA)	91%	90%	88%	92%
Peak Load After Redistribution [MVA]*		40.15	39.64	58.13
Peak / New Firm Capacity**		90%	88%	87%
*Capacitors installed for PF=1 **New 22.4 MVA transformer added by 2040				

4.1.7 Perche Creek Substation

Perche Creek is located on Ludwick Blvd. at LAT: 38.94276294 LON: -92.40282237. This substation's firm capacity (22.4 MVA) is already exceeded as shown in Table 4-8 and actions are required. Under Proposal I the recommendation is to expand the capacity (from 2x22.4 to 3x22.4 MVA) as soon as possible and by 2040 load from Hinkson Creek to the east can be transferred to Perche Creek, without exceeding the new firm capacity. The third image on Figure 4-9 shows the area expanded under Proposal I by 2040.

Table 4-8 summarizes the substation's the peak loads and loading through the years of study.

Figure 4-9 Perche Creek Substation – Proposal 1

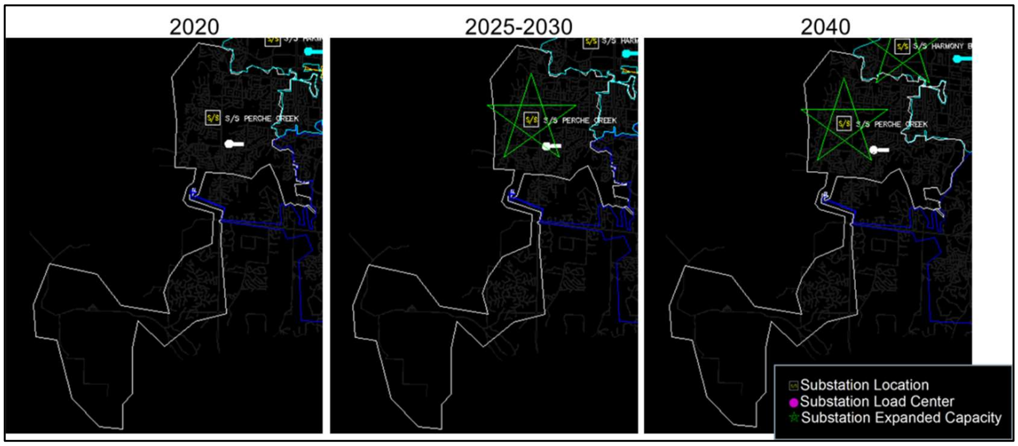


Table 4-8: Perche Creek Loading

Perche Creek	2020	2025	2030	2040
Forecasted Peak Load [MVA]	36.08	36.01	35.32	36.42
Peak / Firm Capacity (22.4 MVA)	161%	161%	158%	163%
Peak Load After Redistribution [MVA]*		36.01	35.32	43.10
Peak / New Firm Capacity**		80%	79%	96%

*Capacitors installed for PF=1
**New 22.4 MVA transformer added by 2025

4.1.8 Hinkson Creek Substation

Hinkson Creek substation is located on Research Park Drive, at LAT: 38.92851066 LON: -92.34024419. The firm capacity (44.8 MVA) is expected to be exceeded by the substation load by 2040 (Table 4-9). Under Proposal I Perche Creek and Harmony Branch can receive part of this substation load to the north as shown in Figure 4-10.

Table 4-9 summarizes the substation's the peak loads and loading through the years of study.

Figure 4-10 Hinkson Substation – Proposal 1

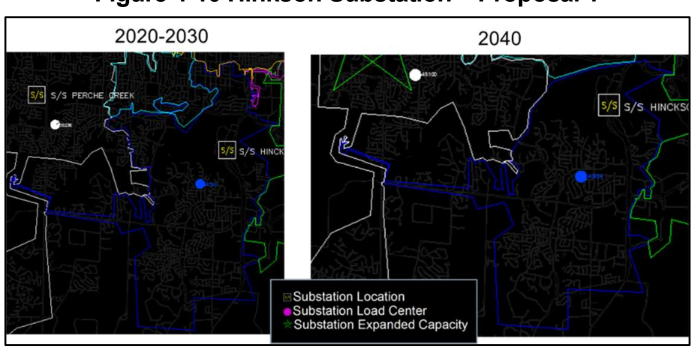


Table 4-9: Hinkson Creek Loading

Hinkson Creek	2020	2025	2030	2040
Forecasted Peak Load [MVA]	**45.17**	**44.47**	**44.83**	**47.41**
Peak / Firm Capacity (2x22.4 MVA)	**101%**	**99%**	**100%**	**106%**
Peak Load After Redistribution [MVA]*		**44.47**	**44.83**	**34.92**
Peak / New Firm Capacity**		**99%**	**100%**	**78%**
***Capacitors installed for PF=1**				
****No Expansion Possible**				

4.2 Proposal II

In this proposal a new substation at south of Perche Creek is assessed to address some of the issues identified for Perche Creek and Hinkson Creek. This substation would serve the residential load south of Perche Creek as well as the water treatment plant and wastewater plant loads, addressing reliability issues and feeder length problems. This substation could also be part of the transmission solutions to create an interconnection at 161 kV from Perche Creek to Grindstone. However, the location of the substation differs from the transmission proposal.

Figure 4-11 shows an overview on how the incorporation of this new substation would affect the coverage areas of Perche Creek and Hinkson Creek southwest of the city, which would be served now by the new substation. We provide below the details of these changes and considerations for the location for the substation. Additionally, a preview of distribution level solutions is provided.

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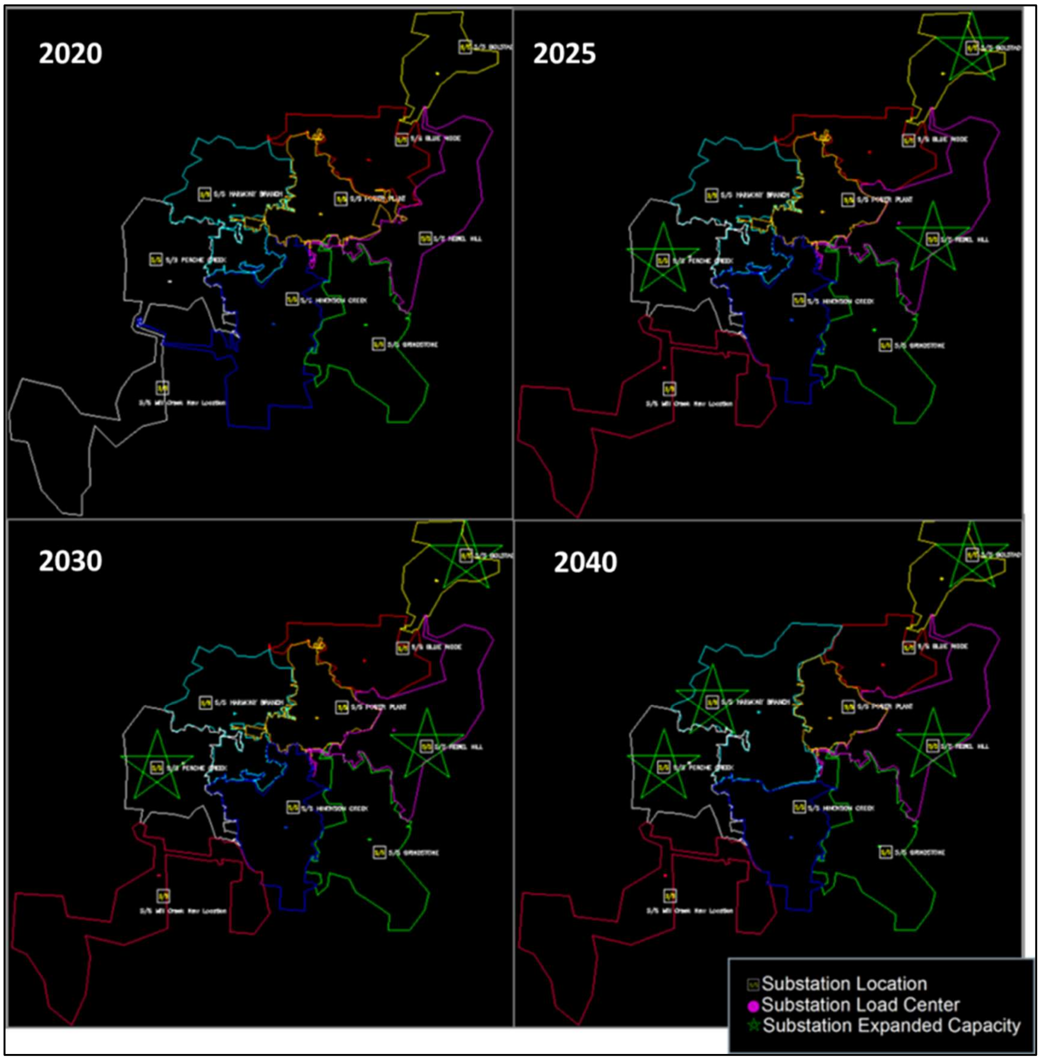
Figure 4-11 Coverage Area Evolution under Proposal II



4.2.1 New Substation

A new substation to serve the area at South of Perche Creek would be another solution to the issues identified with Perche Creek and Hinkson Creek. These issues include exceeding of the firm capacity and the overextension of the feeders resulting in reliability issues. The location of the originally proposed Mill Creek substation (pointed with a red arrow in Figure 4-12) was analyzed but it was found to be too far from the area to be addressed (south of Perche Creek and Hinkson Creek).

A location for a new Substation was identified on S Scott Blvd, at LAT: 38.89669295 LON: -92.39954126. This location would greatly reduce the length of the feeders and would be able to serve any load in that area. Figure 4-13 shows in magenta the preliminary coverage area recommended.

Figure 4-12 Mill Creek Substation Location

Figure 4-13 New Substation

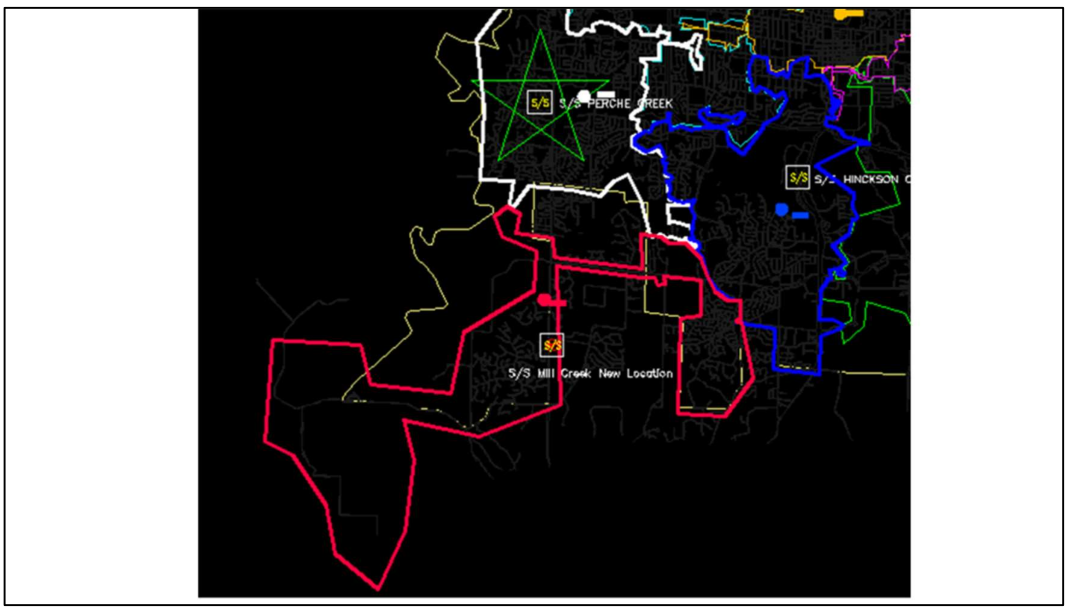


Table 4-10 shows the expected loading of this substation over the years. However, as discussed below the load taken from Perche Creek and Hinkson Creek would not be enough to prevent these substations to exceed their firm capacities.

Table 4-10: New substation Loading – Proposal II

New Substation	2025	2030	2040
Forecasted Peak Load [MVA]	13.42	13.25	13.50
Peak / Firm Capacity (22.4 MVA)*	60%	59%	60%
*Capacitors installed for PF=1			

4.2.2 Perche Creek – Proposal II

As discussed above, the new substation would take most of the load south of Perche Creek addressing reliability and feeder length issues. However, the transferring of this load is not enough to prevent the firm capacity to be exceeded and the expansion in capacity from 2x22.4 to 3x22.4 MVA is still necessary as shown in Table 4-11, where we note that the remaining load after the transfer is 28.63 MVA.

Figure 4-14 shows the new coverage area of Perche creek with the transfer to the new substation.

Figure 4-14 Perche Creek Substation – Proposal 2

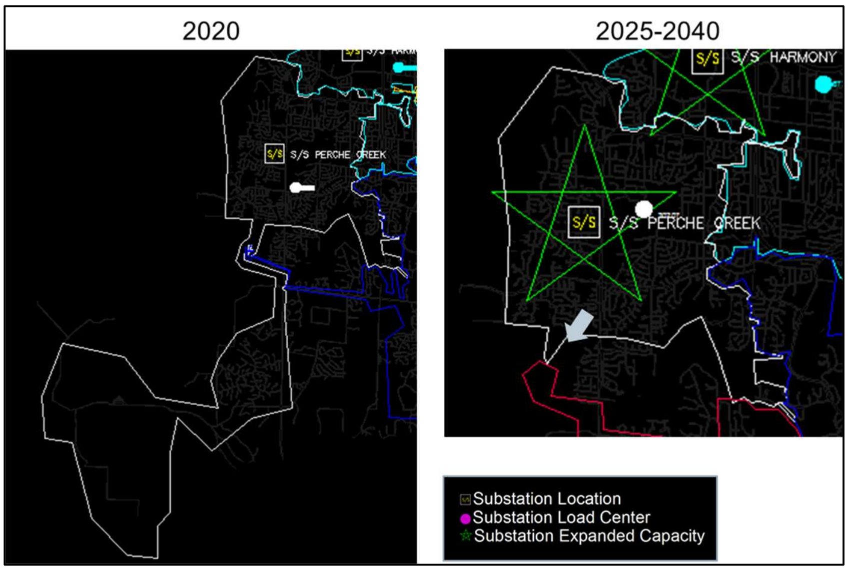


Table 4-11: Perche Creek Loading – Proposal II

Perche Creek - Proposal 2	2020	2025	2030	2040
Forecasted Peak Load [MVA]	36.08	36.01	35.32	36.42
Peak / Firm Capacity (22.4 MVA)	161%	161%	158%	163%
Peak Load After Redistribution [MVA]*		28.63	27.98	28.88
Peak / New Firm Capacity**		64%	62%	64%

*Capacitors installed for PF=1
**New 22.4 MVA transformer added by 2025

4.2.3 Hinkson Creek – Proposal II

Similarly, to Perche Creek, the new substation studied would take all the area Southwest of Hinkson Creek; however, by 2040 the firm capacity of this substation would still be exceeded. Harmony branch could take the load at North. Figure 4-15 shows the new shape of Hinkson Creek and Table 4-12 the loading through the years of study.

Figure 4-15 Hinkson Substation – Proposal 2

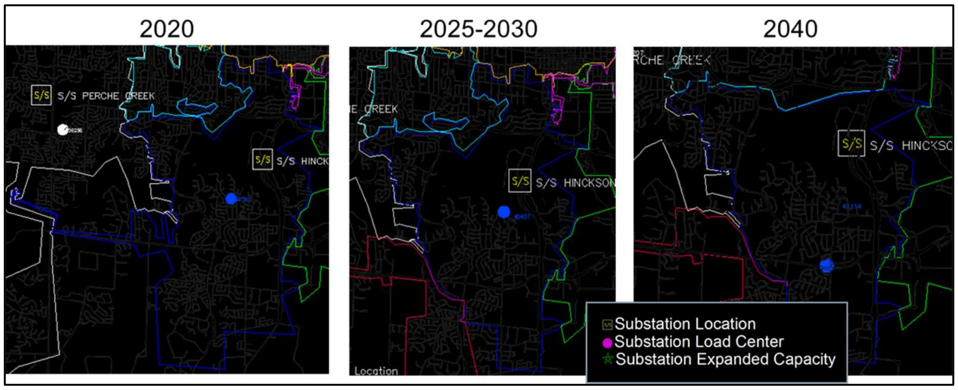


Table 4-12: Hinkson Creek Loading – Proposal II

Hinkson Creek - Proposal 2	2020	2025	2030	2040
Forecasted Peak Load [MVA]	45.17	44.47	44.83	47.41
Peak / Firm Capacity (2x22.4 MVA)	101%	99%	100%	106%
Peak Load After Redistribution [MVA]*		38.38	38.89	35.42
Peak / New Firm Capacity**		86%	87%	79%

*Capacitors installed for PF=1
**No Expansion Possible

4.2.4 Proposal II Observations

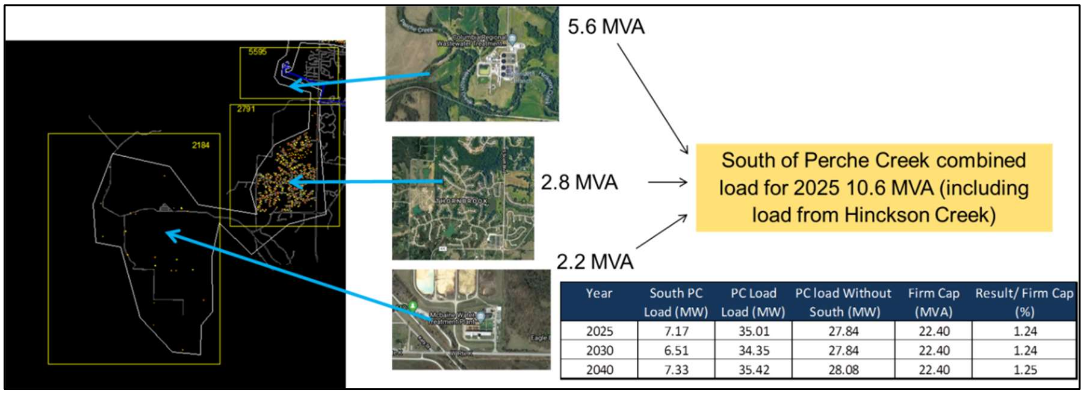
As shown above, the building of the new substation is not enough to prevent the need for Perche Creek to be expanded and the transferring of load out of Hinkson Creek over the long term. The only immediate benefit is one of reliability and this could be addressed with a non-wires solution as well as presented next and discussed in detail on the distribution section of this report. Moreover, for the transmission solution this substation is not necessary as the so called Solution A now has a 161 kV line direct from Perche Creek to Grindstone and there is no connection to Mc Baine sub, which would be done at this substation.

Based on the above this new substation is not recommended at this time and this recommendation should be revisited if there are changes in the load growth patterns with new development plans for the southwest.

4.2.5 Non Wires Alternative South of Perche Creek

Another option was explored for the south of Perche Creek Area. This is to address the over extension of feeders out of Perche Creek and reliability issues creating microgrids with local generation (PV + Storage). As seen on Figure 4-16 a high level review identified approximately 10.6 MW that could be served locally and reduce the load at Perche Creek to 27.84 MW by 2025 and 28.08 MW by 2040. This option is assessed in more detail on the distribution section of this report.

Figure 4-16 Other Alternative at South Perche Creek



Year	South PC Load (MW)	PC Load Load (MW)	PC load Without South (MW)	Firm Cap (MVA)	Result/ Firm Cap (%)
2025	7.17	35.01	27.84	22.40	1.24
2030	6.51	34.35	27.84	22.40	1.24
2040	7.33	35.42	28.08	22.40	1.25

4.3 CONCLUSIONS AND RECOMENDATIONS

In general, CWL substations are capable to serve the city's load the next 20 years, however when considering the firm capacity requirements of the substation limitations arise with most of the substations.

The priority is to attend the substations whose firm capacity has already been exceeded. Table 4-13 summarizes the installed transformer capacity at each of the substations and we observed that new transformers are required for Bolstad, Perche Creek and Revel Hill in the short term (2025) and Harmony Branch in the long term.

Table 4-13: Substation Installed Transformer Capacity

Future capacity	2020	2025	2030	2040	Observation
Substation	**[MVA]**	**[MVA]**	**[MVA]**	**[MVA]**	
Bolstad	**44.8**	**67.2**	**67.2**	**67.2**	**Add a third 22.4 MVA Transformer by 2025**
Blue Ridge	**44.8**	**44.8**	**44.8**	**44.8**	
Grindstone	**67.2**	**67.2**	**67.2**	**67.2**	
Harmony Branch	**67.2**	**67.2**	**67.2**	**89.6**	**Add a fourth 22.4 MVA Transformer by 2040**
Hinkson Creek	**67.2**	**67.2**	**67.2**	**67.2**	
Perche Creek	**44.8**	**67.2**	**67.2**	**67.2**	**Add a third 22.4 MVA Transformer by 2025**
Power Plant	**67.2**	**67.2**	**67.2**	**67.2**	
Rebel Hill	**56**	**84**	**84**	**84**	**Add a third 28 MVA Transformer by 2025**
New Substation	***0***	***40***	***40***	***40***	***At least 2 x 20 MVA required (option not recommended)***

The new substation in the table above (Proposal II) is not recommended at this time, as it is not enough to prevent any of the required expansions required in the existing substations, also shown in the table. However, is important keep track of the city's plans for new developments and growth, and in the case that the southwest of the city (around Thornbrook) is developed, and new roads and subdivisions are built, then the new substation could be justified as this load would be beyond the natural reach Perche Creek, i.e., excessive feeders. However, as this moment City's comprehensive plan does not foresee any new development to the southwest.

Additionally, it should be highlighted at this time that the expansion at Harmony Branch forecasted by 2040 can probably be avoided with the medium voltage distribution level investments detailed in Section 5 sub-section 5.8).

The Tables Table 4-14 and Table 4-15 below summarizes each substation load for the two proposals and as indicated above Proposal II is not recommended.

Table 4-14: Substation Load Proposal I (recommended)

Proposa I		At system peak load			At their own Peak Load		
NAME	Peak 2020 [MW]	2025 Load [MW]	2030 load [MW]	2040 Load [MW]	2025 Load [MW]	2030 load [MW]	2040 Load [MW]
Bolstad	14.28	16.20	19.09	25.31	27.47	32.38	42.93
Blue Ridge	23.84	18.94	19.57	18.28	18.94	19.57	18.28
Grindstone	34.90	36.73	37.48	38.88	43.91	44.80	46.48
Harmony Branch	40.55	40.15	39.64	58.13	40.15	39.64	58.13
Hinkson Creek	45.15	44.45	44.82	34.91	44.47	44.83	34.92
Perche Creek	35.08	35.01	34.35	41.91	36.01	35.32	43.10
Power Plant	47.77	40.95	41.31	36.46	44.02	44.41	39.19
Rebel Hill	31.72	43.79	44.83	50.71	43.79	44.83	50.71
Total	273.28	276.21	281.08	304.59	298.75	305.79	333.75

Table 4-15: Substation Load Proposal II

Proposa II		At system peak load			At their own Peak Load		
NAME	Peak 2020 [MW]	2025 Load [MW]	2030 load [MW]	2040 Load [MW]	2025 Load [MW]	2030 load [MW]	2040 Load [MW]
Bolstad	14.28	16.20	19.09	25.31	27.47	32.38	42.93
Blue Ridge	23.84	18.94	19.57	18.28	18.94	19.57	18.28
Grindstone	34.90	36.73	37.48	38.88	43.91	44.80	46.48
Harmony Branch	40.55	40.15	39.64	58.13	40.15	39.64	58.13
Hinkson Creek	45.15	38.37	38.87	35.40	38.38	38.89	35.42
Perche Creek	35.08	27.84	27.21	28.08	28.63	27.98	28.88
Power Plant	47.77	40.95	41.31	36.46	44.02	44.41	39.19
Rebel Hill	31.72	43.79	44.83	50.71	43.79	44.83	50.71
New Substation		13.25	13.09	13.33	13.42	13.25	13.50
Total	273.28	276.21	281.08	304.59	298.71	305.75	333.52

Lastly the number of Capacitor banks to maintain the unit power factor was also calculated for a 1200 kVA standard bank, the Table 4-16 summarizes this result.

Table 4-16: Summary of Capacitor Banks Needed for Unit Power Factor

SS Name	Capacitors installed 2020	New Capacitor banks needed 2025	New Capacitor banks needed 2030	New Capacitor banks needed 2040
	[MVAR]	[x1200 kVAr]	[x1200 kVAr]	[x1200 kVAr]
Bolstad	12.9	3	5	10
Blue Ridge	10.8	0	0	1
Grindstone	15	4	5	5
Harmony Branch	29.7	0	0	0
Hinkson Creek	20.1	0	0	1
Perche Creek	13.5	0	0	0
Power Plant	19.5	3	4	4
Rebel Hill	16.95	2	2	4
Totals		12x1200 kVAr	16x1200 kVAr	25x1200 kVAr

5 Distribution Network System Assessment

5.1 Introduction

This section of the report provides the results of the short (2025), medium (2030) and long term (2040) performance of CWL distribution system and need for reinforcements. This section first covers the modeling of the distribution network, assumptions made, and is followed by the planning criteria used in the study. These two sections form the foundation that is followed by the assessment of the distribution network under normal conditions (system intact) and under emergency conditions with one critical element out of service (typically the first section out of a substation). Finally, we present the performance of the network with the proposed reinforcements in place under peak load and minimum load conditions with maximum distributed generation and provide confirmation of the substation transformer capacity expansion discusses earlier in this report.

5.2 Distribution Network Modelling

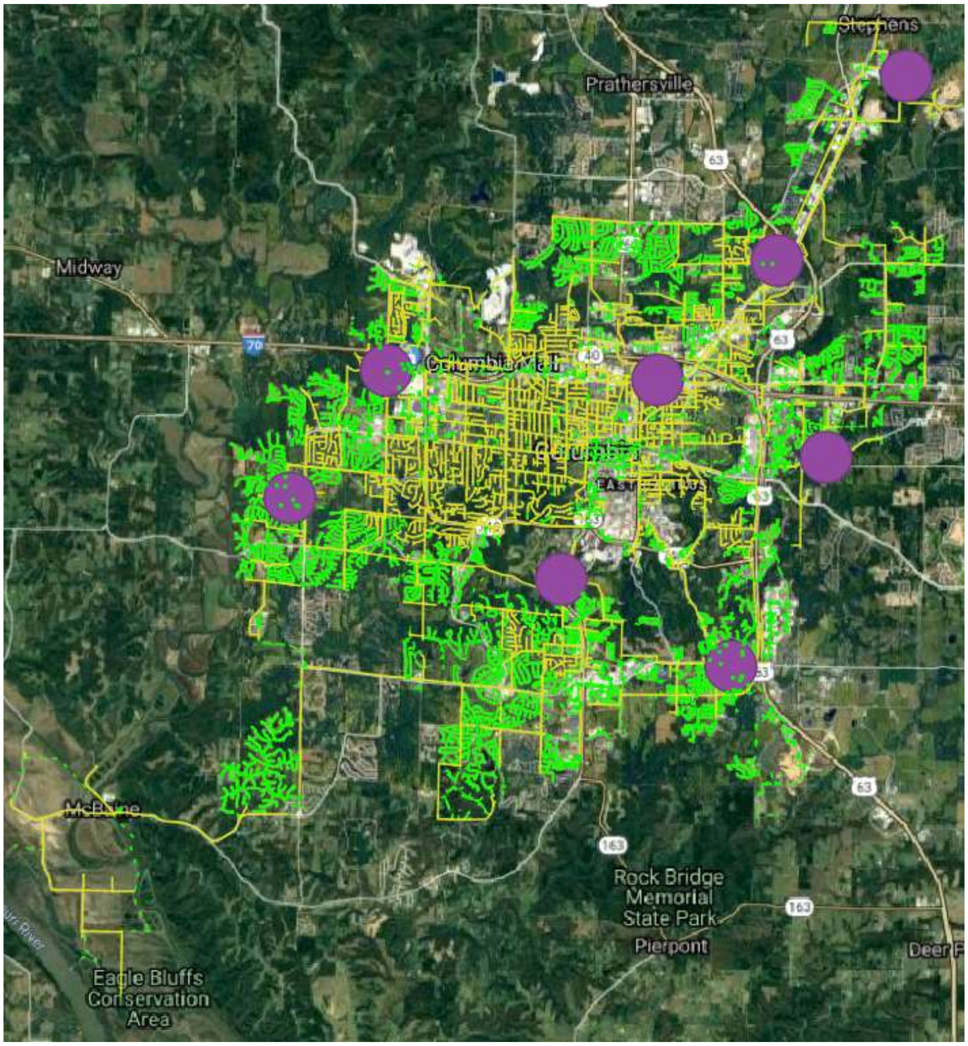
5.2.1 Provided Data and Network Modeling Strategy

CWL provided a geographical distribution network model in CYME power system software and GIS data (Figure 5-1). The CYME distribution network model was originally intended to be updated for this study, but it was found that it had incomplete representation of the distribution transformers, which were modeled as equivalent and made it unsuitable for the representation of the spatial load forecast and for feeder analysis.

On the other hand, provided GIS data was up to date and included all feeders, and distribution transformer locations as required especially for spatial load forecast. Therefore, the GIS data was selected as a base data source for distribution network modeling. GIS data was converted to PSS®SINCAL which is Siemen's power system analysis software and widely used for distribution system planning topics.

While converting the data from GIS to PSS®SINCAL, all available data was examined to ensure accuracy of the model. In this process, some issues were detected and corrected as explained below.

Figure 5-1 An overview of provided GIS data – Electric.gdb



5.2.2 Limitations of Distribution Network Model

CWL distribution network was modelled starting from the high voltage (HV) substations, transformers to medium voltage (MV), MV system and distribution transformers to low voltage (LV) were explicitly modeled and assessed. All loads are connected to low voltage (LV) side of distribution transformers which provided adequate load allocation along the feeder and consideration of transformer losses. Assessment and investments at the LV system are typically beyond the scope of master plans, due to their detailed and localized nature.

5.2.3 Missing Data in Network Model and Assumptions

5.2.3.1 Conductor Sizes

Main incomplete information in the GIS data was conductor size. The only available information related to conductors was the ampacity class (as 200 Amps and 600 Amps) and construction type overhead/underground.

The conductor sizes were identified working with CWL engineers and the conductor below were implemented in the model by application type.

- 500 Cu cables for 600 Amps class underground mainlines protected by breaker or recloser.
- 477 ACSR for 600 Amps class overhead mainlines protected by breaker or recloser.
- 4/0 AL cable for 200 Amps class underground laterals protected by fuse.
- 1/0 ACSR for 200 Amps class overhead laterals protected by fuse.

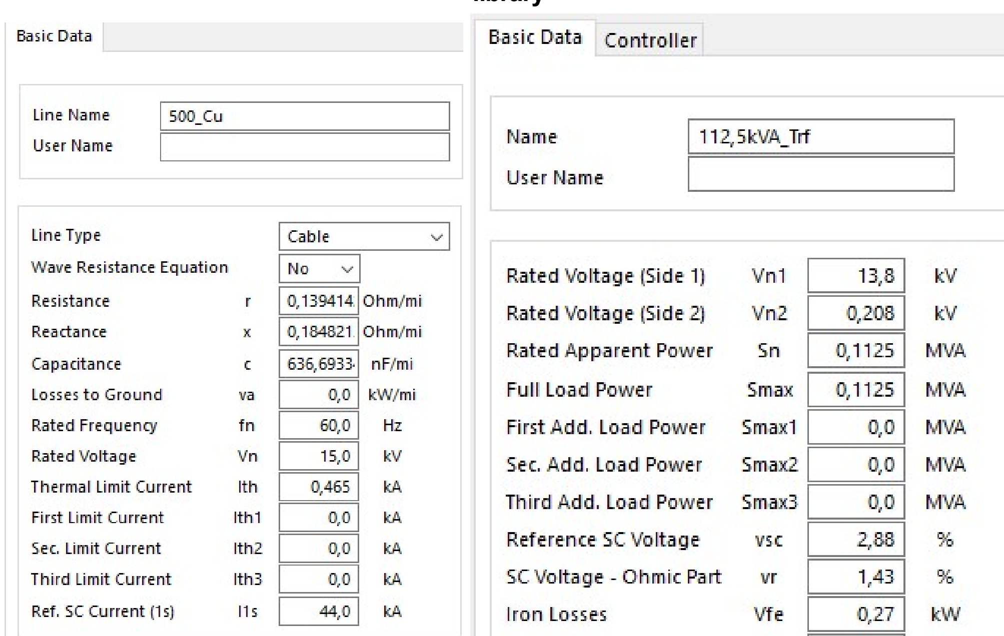
There might be some exceptions to the above in practice. However, they are negligible for planning purposes.

5.2.3.2 Equipment Parameters

Electrical parameters are necessary for the accurate representation of the network. Master equipment libraries for conductors and distribution transformers were created using manufacturer catalogues, prior studies equipment libraries.

Some examples are shown for 500 kcmil-CU conductors and 112.5 kVA distribution transformers respectively in Figure 5-2.

Figure 5-2 An overview conductor and transformer master library



5.2.4 Load Assumptions

Load allocation down to the different distribution transformers is the central point for assessing the distribution system. The load data provided by CWL was examined thoroughly to cross check it and produce a network model ready for further analysis. The provided load data is listed below:

- Feeder Head Load Measurement by substation and transformer
- Crystal reports and account list including billing data

5.2.4.1 Feeder Head Measurement Analysis

Demand (MW) measurements for each feeder head was provided between June 2016 and November 2019 in 5-minute interval resolution. In order to reflect current loading status of the network, only 2019 measurements were evaluated. Load data between 2016 and 2019 was used to assess the level of load changes variation from previous years.

Feeder head measurements were adjusted as follows:

1. Conversion from 5-minute interval to hourly average:

   Load data in 5-minute interval resolution can be very volatile, and it could create some artificial peaks. Therefore, 5-minute interval load data for each hour was averaged to minimize the chances of artificial peaks and influence of measurement errors.

2. Identification of load transfers to adjacent feeders.

   As a nature of operation in distribution system, sections or entire feeders can be transferred to adjacent feeders, which affects the feeder head measurements of the receiving feeders. If load transfers are not eliminated from feeder head measurements, feeder loads will be higher than normal and result in an overstatement of the contingency overloads on distribution system.

   In order to eliminate the influence of these load transfers, hourly averaged feeder head measurements were sorted according to the time stamps and if any 0 measurement was found in any feeder, all measurements belong this time stamp were deleted. Therefore, most if not all of the load transfers were eliminated.

After these two main corrections were implemented to the data, feeder loading was processed to determine individual feeder peak load, feeder load at the time of system peak and feeder load at the time of minimum system load.

5.2.4.2 Distribution Transformer Measurement Analysis

As mentioned before, load allocation along the feeder is critical for accurate assessment of distribution system and account for the effects of distribution transformer location.

CWL provided crystal reports and account list including billing data and connected transformer codes. If there is a demand meter for the account, load value in kW is available in billing data. Otherwise, demand of the account, which has only consumption data, was estimated by using a load factor consistent with CWL experience. Load factors were available in billing data for each account. The reactive power consumption of the loads was estimated using typical power factors as shown in Table 5-1.

Table 5-1: Power factor for each load type

Customer Type	Power Factor
SGS	0.85
Residential	0.99
LGS	0.85
Outdoor Lights	0.99
Industrial	0.85

2019 Crystal reports and billing data dated as was used which are consistent with the latest distribution network structure in GIS and feeder head measurements. As CWL system peak happened in July 2019 the loading in the network model was done for July. If there was no billing information for July for any account, the maximum measured for 2019 was assumed.

Demand of each distribution transformer was calculated using the correlation between each customer account and the associated transformer numbers and by summing the demand of all the accounts connected. If there was no connected account to any give distribution transformer, the assumption was that the transformer would be loaded as average loading of same transformer size in the network. A part of distribution transformer measurement analysis is shown in Table 5-2.

Table 5-2: Part of distribution transformer measurement analysis

Location Number	Feeder ID	Capacity	Transformer Customer Type	Calc kW	Calc kVAr	Calc kVA	Calc Power Factor	Assumed kW	Assumed kVAr	Assumed kVA	Assumed Power Factor	Final kW	Final kVAr	Final kVA	Final Power Factor
3779	PC223	50	Residential	10.08	1.48	10.19	0.99					10.08	1.48	10.19	0.99
3781	PC223	50	Residential	15.88	2.25	16.04	0.99					15.88	2.25	16.04	0.99
3783	PC223	50	Residential	16.4	2.29	16.56	0.99					16.4	2.29	16.56	0.99
3784	PC223	50	Residential	7.32	1.08	7.4	0.99					7.32	1.08	7.4	0.99
3787	PC223	50	Residential	5.98	0.85	6.04	0.99					5.98	0.85	6.04	0.99
3788	PC223	50	Residential	7.19	1.01	7.26	0.99					7.19	1.01	7.26	0.99
3785	PC223	50	Residential	13.86	1.91	13.99	0.99					13.86	1.91	13.99	0.99
2298	PC213	50	Residential	7.95	1.78	8.24	0.96					7.95	1.78	8.24	0.96
3728	PC213	75	Residential	15.41	2.4	15.65	0.98					15.41	2.4	15.65	0.98
3731	PC213	50	Residential	17.76	2.46	17.93	0.99					17.76	2.46	17.93	0.99
3732	PC213	50	Residential	7.4	1.07	7.48	0.99					7.4	1.07	7.48	0.99
3735	PC213	50	Residential	11.54	1.6	11.65	0.99					11.54	1.6	11.65	0.99
3736	PC213	25	Residential	4.52	0.67	4.57	0.99					4.52	0.67	4.57	0.99
3740	PC213	50	Residential	11.19	1.57	11.3	0.99					11.19	1.57	11.3	0.99
5008	HB212	112.5	C or I	15.2	9.42	17.88	0.85					15.2	9.42	17.88	0.85
5125	RH211	25	C or I	0	0	0	0	9.49	5.87	11.16	0.85	9.49	5.87	11.16	0.85
11913	BD223	25	C or I	0	0	0	0	9.49	5.87	11.16	0.85	9.49	5.87	11.16	0.85

5.2.4.3 Load Scenarios

The main purpose of network planning is strengthening the network to provide safe, reliable, and economic service to customers considering future loads and demands. Therefore, the distribution network should be analyzed under different load scenarios to identify possible future bottleneck and performance issues before they materialize in practice.

The central load scenario is the individual feeder peak load condition under which each feeder is analyzed considering its own individual peak load. This scenario represents the maximum stresses for the feeder and adjacent feeders that may take some of the loads of the feeder are also considered at their individual peak, thus providing some level of conservativism. Note that adjacent feeders typically peak close to the same time due to feeding similar load types.

A second scenario is the system peak load condition under which each feeder is analyzed under its load at the time of the system peak. It provides a view on the most stressed parts of the system.

The final scenario is noon time minimum coincident load of CWL distribution system with maximum distributed generation output. The main purpose of this scenario is analyzing voltage profiles and possibility of back feeding to the transmission network.

Based on the above, three load scenarios were defined:

1. Individual feeder peak load condition without DG contribution
2. System peak load condition without DG contribution
3. Minimum system load conditions with maximum DG contribution

It is assumed that in each scenario the loads connected to the same feeder behave homogenously from system peak to individual peak or minimum load condition or vice versa. Thus, scale factors are calculated for each feeder to create these load scenarios.

Feeder loads at individual feeder, system peak, and minimum system load conditions are shown in Table 5-3. All load scenarios are analyzed under 2025, 2030 and 2040 future load conditions and shown in PSS®SINCAL variant structure in Figure 5-3

Figure 5-3 Proposed load scenarios in PSS®SINCAL variant structure

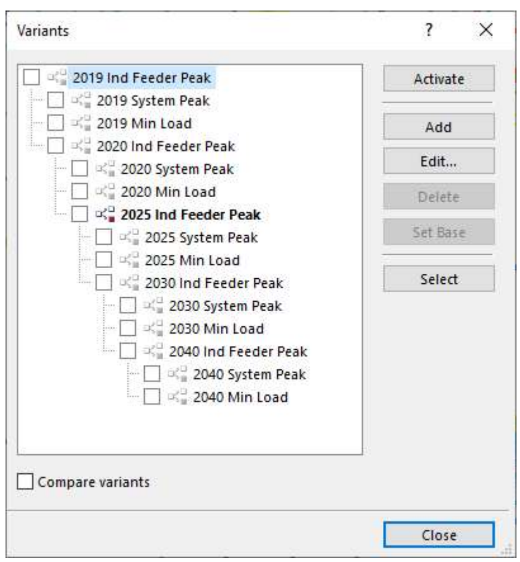


Table 5-3: Feeder loads at individual feeder, system peak and minimum system load conditions

Substation	Feeder	Time@Ind. Feeder Peak	Load@Ind. Feeder Peak	Time@System Peak	Load @System Peak	Time@ Min. System Peak	Load@ Min. System Peak
	2019						
Bolstad	BD211	24.01.2019 18:00	1.90	19.07.2019 16:00	1.22	24.03.2019 12:00	0.96
	BD212	13.08.2019 11:00	4.13	19.07.2019 16:00	1.75	24.03.2019 12:00	1.11
	BD213	10.07.2019 11:00	5.68	19.07.2019 16:00	3.63	24.03.2019 12:00	2.85
	BD221	13.03.2019 08:00	0.33	19.07.2019 16:00	0.33	24.03.2019 12:00	0.33
	BD222	10.07.2019 12:00	5.27	19.07.2019 16:00	3.34	24.03.2019 12:00	2.16
	BD223	20.08.2019 15:00	4.74	19.07.2019 16:00	3.52	24.03.2019 12:00	2.29
Blue Ridge	BR211	19.07.2019 16:00	5.32	19.07.2019 16:00	5.32	24.03.2019 12:00	1.86
	BR212	19.08.2019 17:00	5.47	19.07.2019 16:00	5.36	24.03.2019 12:00	1.71
	BR213	19.07.2019 17:00	4.60	19.07.2019 16:00	4.59	24.03.2019 12:00	2.10
	BR221	12.08.2019 18:00	1.34	19.07.2019 16:00	1.25	24.03.2019 12:00	0.43
	BR222	19.07.2019 16:00	5.45	19.07.2019 16:00	5.45	24.03.2019 12:00	1.95
	BR223	01.01.2019 00:00	0	19.07.2019 16:00	0	24.03.2019 12:00	0
Grindstone	GD211	19.07.2019 16:00	4.95	19.07.2019 16:00	4.95	24.03.2019 12:00	2.02
	GD212	19.07.2019 16:00	4.69	19.07.2019 16:00	4.69	24.03.2019 12:00	1.70
	GD213	30.01.2019 07:00	3.66	19.07.2019 16:00	2.84	24.03.2019 12:00	1.18
	GD221	19.08.2019 13:00	3.62	19.07.2019 16:00	2.74	24.03.2019 12:00	0.84
	GD222	30.01.2019 07:00	5.44	19.07.2019 16:00	4.89	24.03.2019 12:00	1.83
	GD223	19.08.2019 15:00	1.91	19.07.2019 16:00	1.79	24.03.2019 12:00	0.83
	GD231	30.01.2019 07:00	5.74	19.07.2019 16:00	2.18	24.03.2019 12:00	0.77
	GD232	30.01.2019 18:00	7.23	19.07.2019 16:00	5.01	24.03.2019 12:00	2.03
	GD233	30.01.2019 06:00	4.70	19.07.2019 16:00	3.48	24.03.2019 12:00	1.62
Harmony Branch	HB211	19.07.2019 15:00	1.78	19.07.2019 16:00	1.77	24.03.2019 12:00	0.61
	HB212	19.07.2019 16:00	3.21	19.07.2019 16:00	3.21	24.03.2019 12:00	1.48
	HB213	19.07.2019 15:00	5.13	19.07.2019 16:00	5.04	24.03.2019 12:00	1.88
	HB221	30.01.2019 18:00	4.86	19.07.2019 16:00	4.36	24.03.2019 12:00	1.56
	HB222	19.08.2019 16:00	5.45	19.07.2019 16:00	4.73	24.03.2019 12:00	1.76
	HB223	24.02.2019 19:00	5.02	19.07.2019 16:00	4.33	24.03.2019 12:00	1.20
	HB231	18.07.2019 15:00	3.63	19.07.2019 16:00	3.39	24.03.2019 12:00	1.52
	HB232	18.07.2019 18:00	5.54	19.07.2019 16:00	5.37	24.03.2019 12:00	1.92
	HB233	19.07.2019 15:00	5.57	19.07.2019 16:00	5.57	24.03.2019 12:00	2.59
Hinkson Creek	HC211	19.08.2019 15:00	6.38	19.07.2019 16:00	6.18	24.03.2019 12:00	2.43
	HC212	19.08.2019 18:00	6.18	19.07.2019 16:00	5.95	24.03.2019 12:00	2.22
	HC213	30.01.2019 07:00	5.14	19.07.2019 16:00	3.63	24.03.2019 12:00	1.57
	HC221	19.07.2019 17:00	5.75	19.07.2019 16:00	5.68	24.03.2019 12:00	2.04
	HC222	01.01.2019 00:00	0.00	19.07.2019 16:00	0.00	24.03.2019 12:00	0.00
	HC223	19.07.2019 17:00	7.67	19.07.2019 16:00	7.63	24.03.2019 12:00	2.88
	HC231	19.07.2019 16:00	4.33	19.07.2019 16:00	4.33	24.03.2019 12:00	1.83
	HC232	17.07.2019 13:00	3.65	19.07.2019 16:00	3.44	24.03.2019 12:00	1.83
	HC233	19.08.2019 17:00	5.73	19.07.2019 16:00	4.90	24.03.2019 12:00	1.62
Perche Creek	PC211	12.08.2019 18:00	5.07	19.07.2019 16:00	4.88	24.03.2019 12:00	1.45
	PC212	19.07.2019 17:00	5.02	19.07.2019 16:00	4.95	24.03.2019 12:00	1.72
	PC213	12.08.2019 18:00	6.19	19.07.2019 16:00	5.64	24.03.2019 12:00	1.36
	PC221	19.07.2019 17:00	7.59	19.07.2019 16:00	7.37	24.03.2019 12:00	2.62
	PC222	19.07.2019 17:00	4.82	19.07.2019 16:00	4.80	24.03.2019 12:00	2.02
	PC223	19.08.2019 18:00	4.48	19.07.2019 16:00	4.18	24.03.2019 12:00	1.46
Power Plant	PL212	18.07.2019 14:00	3.63	19.07.2019 16:00	3.19	24.03.2019 12:00	1.13
	PL213	19.07.2019 17:00	6.57	19.07.2019 16:00	6.52	24.03.2019 12:00	2.13
	PL214	18.07.2019 16:00	5.30	19.07.2019 16:00	5.13	24.03.2019 12:00	2.11
	PL221	19.07.2019 15:00	4.23	19.07.2019 16:00	4.19	24.03.2019 12:00	1.50
	PL222	19.07.2019 16:00	4.81	19.07.2019 16:00	4.81	24.03.2019 12:00	1.77
	PL223	19.08.2019 14:00	6.89	19.07.2019 16:00	6.33	24.03.2019 12:00	2.82
	PL231	10.07.2019 11:00	5.16	19.07.2019 16:00	4.93	24.03.2019 12:00	2.94
	PL232	19.07.2019 16:00	4.51	19.07.2019 16:00	4.51	24.03.2019 12:00	1.65
	PL233	19.07.2019 16:00	5.15	19.07.2019 16:00	5.15	24.03.2019 12:00	1.47
Rebel Hill	RH211	17.07.2019 14:00	7.55	19.07.2019 16:00	7.38	24.03.2019 12:00	3.75
	RH212	30.01.2019 18:00	6.50	19.07.2019 16:00	5.27	24.03.2019 12:00	2.07
	RH213	30.01.2019 07:00	3.14	19.07.2019 16:00	2.61	24.03.2019 12:00	1.13
	RH214	20.07.2019 16:00	5.04	19.07.2019 16:00	4.91	24.03.2019 12:00	1.68
	RH221	17.07.2019 14:00	3.21	19.07.2019 16:00	3.06	24.03.2019 12:00	1.69
	RH222	30.01.2019 07:00	2.54	19.07.2019 16:00	2.20	24.03.2019 12:00	1.10
	RH223	30.01.2019 08:00	1.45	19.07.2019 16:00	1.24	24.03.2019 12:00	0.51
	RH224	06.03.2019 06:00	5.02	19.07.2019 16:00	2.96	24.03.2019 12:00	1.19

5.2.5 Switching Status

Supply area of each feeder and each substation should align with that at the time of the measurements. Therefore, switching conditions of the system should reflect normal operating conditions as should have been present at the time the feeder head measurements were takes.

The switching status (normal open/ close points) under normal operation was modeled as provided GIS data and were considered accurate to configure radial operation in the entire network. There were some small exceptions which caused small loops and they were fixed to prevent circulating current.

5.2.6 Existing Distribution Network Model Overview

As described in this report, CWL distribution network model was created by converting GIS data to PSS®SINCAL and load scenarios and future load growth are implemented on it.

Figure 5-4 provides an overview of the CWL existing distribution system model with the coverage area of each substation in the system. Coverage areas for each substation are highlighted with different colors. Figure 5-5 provides an additional overview of the individual feeders by substation using different colors. The distribution model in PSS®SINCAL is used as a starting point of the analysis.

Figure 5-4 An overview of CWL existing distribution network model (colored as substation base)

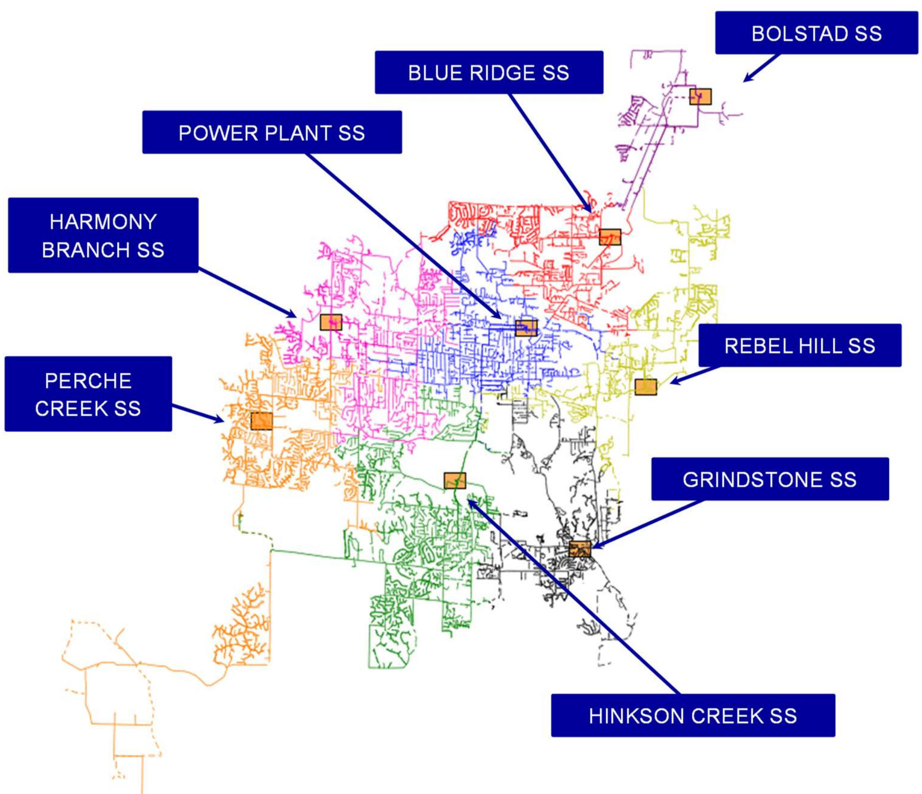
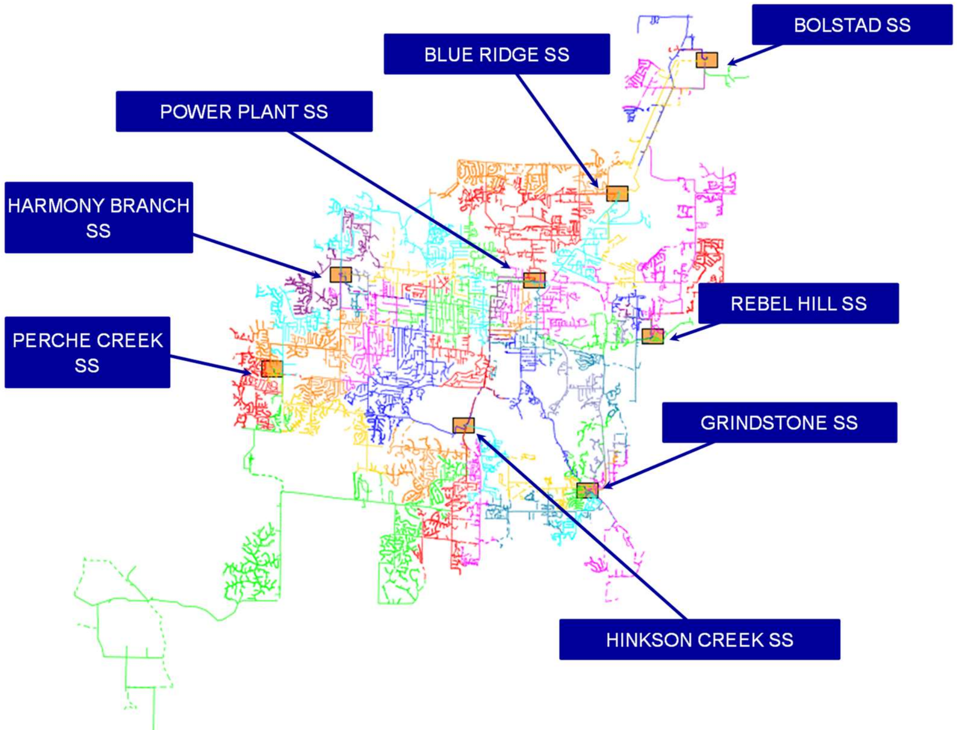


Figure 5-5 An overview of CWL existing distribution network model (colored as feeder base)



5.3 Distribution Network Planning Criteria

Planning criteria is a set of rules that are used to design and assess the performance of network.

There are elements of the planning criteria that are uniform across utilities in the US and some that are specific to each utility. We present next a summary the planning criteria used in this project that reflect CWL practices as derived from our exchanges with staff and our recommendations.

The planning criteria includes the topics below.

Normal & emergency operation criteria

- Voltage limits
- Loading limits
- Contingency criteria
- Number of switching maneuvers

Standard equipment

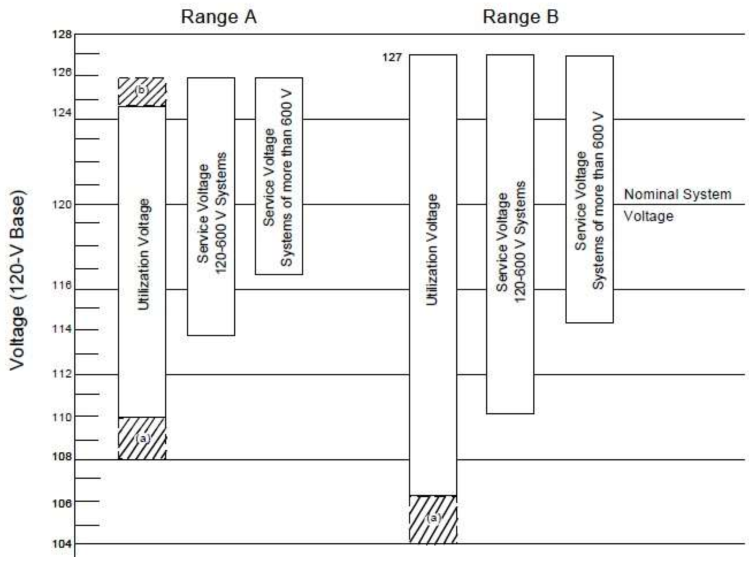
- Conductors
- Distribution transformers
- Substation design (distribution side)
- Capacitor banks

5.3.1 Normal and Emergency Operation Criteria

5.3.1.1 Voltage Limits

According to ANSI C84.1 for systems greater than 600 V, the service limits are as shown in Figure 5-6. This is a minimum standard that must be met.

Figure 5-6 ANSI C84.1 service voltage limit for systems greater than 600 V



Range A is for normal conditions. Range B is for short emergency conditions.

- Range A minimum voltage is 97.5% of nominal voltage
- Range A maximum voltage is 105% of nominal voltage
- Range B minimum voltage is 95% of nominal voltage
- Range B maximum voltage is 105.8% of nominal voltage

Voltage limits for CWL system are defined by using CWL engineering guidelines and based on ANSI C84.1. In this guideline 2% voltage drop in transformer,1% voltage drop in secondary, and 1% voltage drop in service are assumed. It should be noted that the guidelines for planning purposes, and it may vary in operation. The voltage limits are shown below for normal conditions, which are also to be maintained in emergency operating conditions.

- Normal Operating Condition
    - Maximum voltage is 103% of nominal voltage
    - Minimum voltage is 99% of nominal voltage

- Emergency Operating Condition
    - Maximum voltage is 103% of nominal voltage
    - Minimum voltage is 99% of nominal voltage

5.3.1.2 Loading Limits

Mainlines should have reserve capacity to provide a backup to adjacent feeders during faults resulting in loss of supply or maintenance. Therefore, planning loading limits for equipment are defined for CWL system as below.

- Lines/Feeder Loading
  - Normal Operating Condition : Maximum loading is 50% to 66% of nominal ampacity
  - Emergency Operating Condition : Maximum loading is 100% of nominal ampacity

Maximum loading under normal operation is a flexible criterion depends on maximum allowed number of switching maneuvers. Loading greater than 50% (or 66%) of nominal ampacity under normal condition is acceptable provided that the conductor will not be overloaded under emergency condition (i.e., when providing backup).

- Substation Transformers
  - Normal Operating Condition : Maximum loading is 100% of ONAFAF capacity
  - Emergency Operating Condition : Maximum loading is 100% of ONAFAF capacity

5.3.1.3 Contingency Criteria

All feeders must have a way to supply the mainline load under emergency (n-1) condition by reconnection of open loops. This criterion is used for both underground and overhead feeders.

Laterals with a load greater than 500 kVA must have a way to reconnect to the mainline (open loop service) in case of a faulted section, limiting the maximum amount of load without means of a backup to 500 kVA.

There should be firm capacity at the substations. This means that upon the loss of one transformers the remaining transformers should be able to supply the entire load and the need to transfer load out should be very limited.

5.3.1.4 Number of Switching Maneuvers

In emergency condition (n-1), load transfer operations to resupply the unaffected part of system should be as easy and expedited as possible. For this, our standard criterion is to limit up to two switching operation.

- Open – Isolating the fault
- Close – Resupply the unaffected part from an adjacent feeder

To limit maximum number of switching to two, enough reserve capacity should be provided for equipment. This is another reason to limit loading of mainline conductors as 50% under normal operation conditions. An alternative to the above is accept 4 operations:

- Open – Isolating the fault
- Sectionalize: split the feeder in two segments (A & B)
- Close – Resupply the unaffected Segment A from adjacent feeder 1
- Close – Resupply the unaffected Segment B from adjacent feeder 2

The second option, unless done automatically with reclosers may take a longer time but allows loading the feeders to 66%.

Depending on the configuration we typically select 50% as the limit to allow for unforeseen load growth in planning but if this would imply important increase in investments, larger loading values and number operations (particularly if automatic) are accepted.

5.3.1.5 Power Factor

Power factor should be kept close to unity for increasing efficiency, reducing losses of system, and especially improving voltage profile. Thus, power factor limits for CWL system are defined as below.

- Normal Operating Condition : Minimum power factor 0.98
- Emergency Operating Condition : Minimum power factor 0.98

5.3.2 Standard Equipment

5.3.2.1 Feeders – Conductors

In CWL system, the conductors below are used as the preferred conductor for mainlines and laterals for underground and overhead lines to be used whenever a new feeder section or reconductoring need is identified.

- 500 Cu (UG) 600 Amps class (in mainlines protected by switch)
- 477 ACSR 600 Amps class (in mainlines protected by switch)
- 4/0 AL (UG) 200 Amps class (in laterals protected by fuse)
- 1/0 ACSR 200 Amps class (in laterals protected by fuse)

As agreed with CWL engineers, new constructions will be underground only, no new overhead system. Thus, 500 kcmil CU was selected for new feeders and reconductoring along the mainlines. It provides a good voltage profile along the mainline, additional capacity for emergency conditions and future load growth. If higher capacity is required doubling the conductor is considered.

Also, we assumed no "telescopic" design in future network. In this last design practice, the size of the conductor is reduced as the mainline moves away from the substation resulting in lower investment levels at the expense of reduce flexibility to provide backup to other feeders or receive backup.

5.3.2.2 Substation Design – Distribution Side

Typical substation design has 3 connected feeders per 20 MVA 69/13.8 kV transformer and 4 connected feeders at Rebel Hill that has 25 MVA 161/13.8 kV transformers. This design criteria was maintained throughout the study and more feeders to transformers.

5.3.2.3 Capacitor Banks

Although different types of capacitor banks are used in CWL system, the 300 kVAr option is the most common. Therefore, 300 kVAr and multiple capacitor banks were selected as standard type.

5.3.3 Planning horizon

The study presented in this report starts from the 2020 condition of CWL distribution network as representative of the current condition and the distribution network is planned under a 5, 10 and 20 year planning horizon, representing short (2025), medium (2030), and long (2040) term respectively. Each condition was modeled considering the forecasted loads and different load scenarios.

5.4 Existing Distribution Network Performance

First step of planning is the thermal and voltage violations analysis for the current system to assess any existing or possible loading and/or voltage issues based on the current distribution system configuration.

The existing distribution system was analyzed under current load (2020) and the forecasted load (2025, 2030, and 2040) without distributed generation (DG) contribution to identify worst conditions from a loading perspective as explained before. The analyses were conducted when each feeder has its peak load. The details of analyses results are shown in next sections.

5.4.1 System analysis under 2020 Feeder Peak Load Conditions

There are no voltage violations under 2020 feeder peak load condition except in the area supplied by PC221 feeder out of Perche Creek Substation. The lowest voltage was detected at PC221 (98.3%), largely in water treatment facility shown in blue in Figure 5-7.

Note that in Figure 5-7 the network is colored according to voltage performance as shown below and the same convention is used for all diagrams in this document showing voltage performance.

- Green : Compliant with the planning criteria
- Blue : Voltage violation (below 0.99 pu but above 0.95)
- Red : Severe voltage violation (under 0.95 pu)

As shown in Figure 5-8, there is no loading violation under 2020 feeder peak load condition. Loading of all lines was less than 100% of their rating (ampacity). Maximum line loading was 97.9% and appeared in the supply area of Grindstone Substation. This is due to small conductor size.

The network is also colored according to the loading as shown below and the same convention is used for all diagrams in this document showing loading.

- Green : Loading less than 70%
- Blue : Loading between 70% and 100%
- Red : Loading greater than 100%

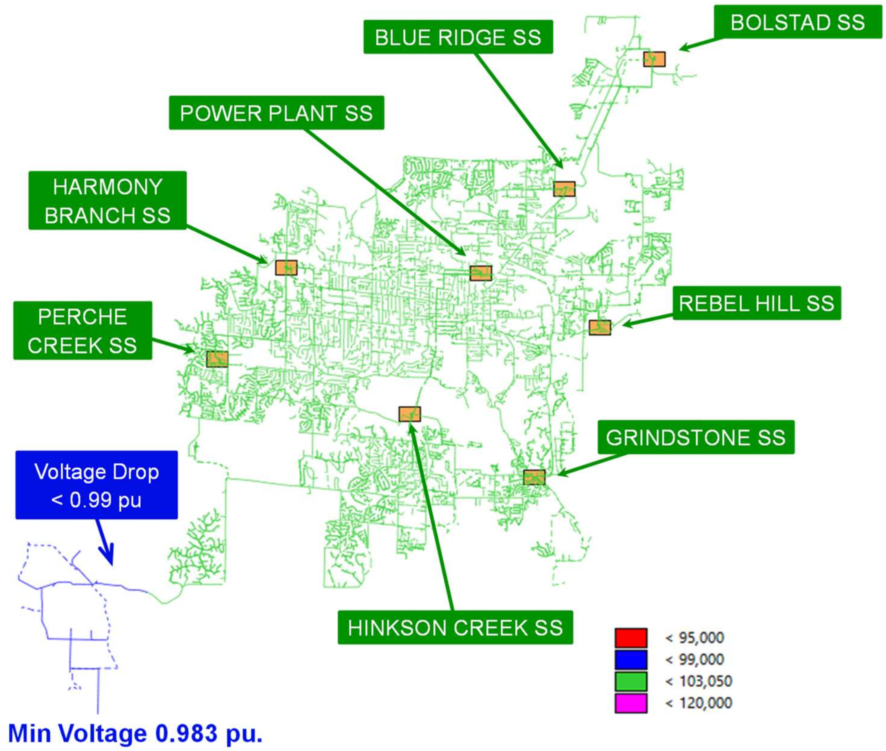


Figure 5-7 Voltage check in 2020 feeder peak load condition

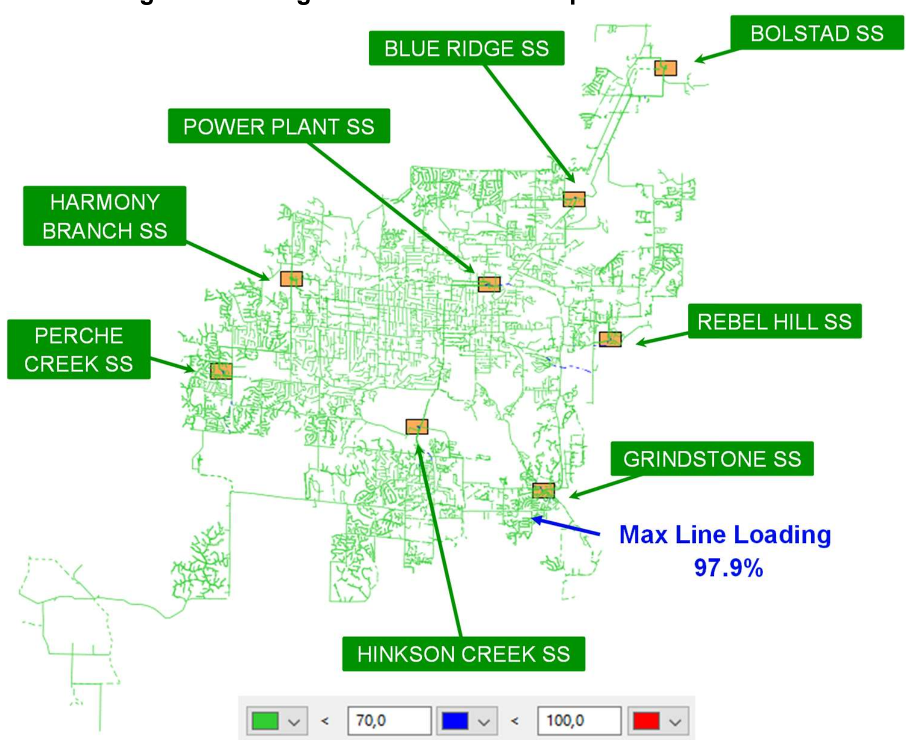


Figure 5-8 Loading check in 2020 feeder peak load condition

5.4.2 System analysis under 2025 Feeder Peak Load Conditions

As in 2020, there is no voltage violation under 2025 feeder peak load condition except in the area supplied by PC221 feeder from Perche Creek Substation. The lowest voltage was again detected in PC221 (98.2%), at the water treatment facility. This is shown in blue in Figure 5-9.

Same as 2020 load condition, there is no loading violation under 2025 feeder peak load condition as shown in Figure 5-10. Maximum line loading was 96.3% in the supply area of Grindstone Substation due to small conductor size.

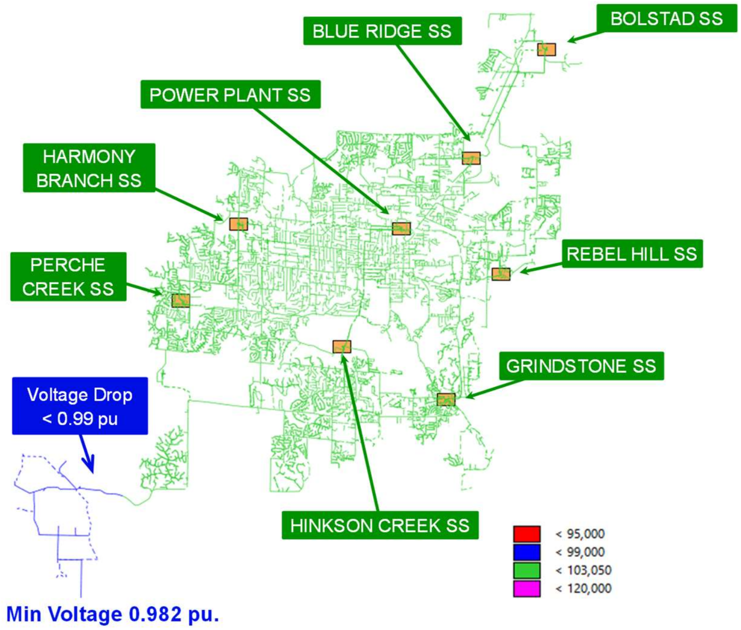


Figure 5-9 Voltage check in 2025 feeder peak load condition

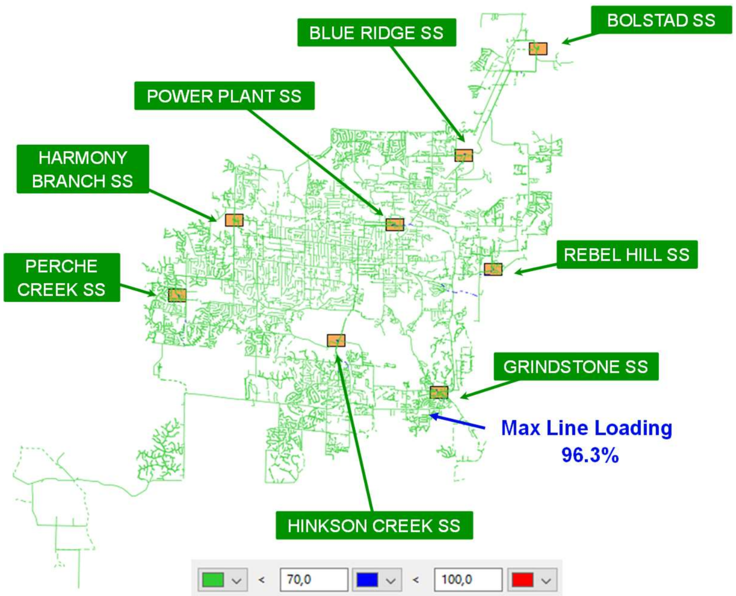


Figure 5-10 Loading check in 2025 feeder peak load condition

5.4.3 System analysis under 2030 Feeder Peak Load Conditions

The situation is same as 2020 and 2025 feeder peak load conditions for 2030. Water treatment area supplied by PC221 feeder has voltage violations; lowest voltage at PC221 (98.4%) shown in blue in Figure 5-11.

In 2030 an overload (101.4% loading) was identified at feeder BR222 under normal operating conditions as shown in Figure 5-12 at the substation exit (getaways). This condition is expected to become worse under emergency if this feeder is intended to provide backup to another feeder.

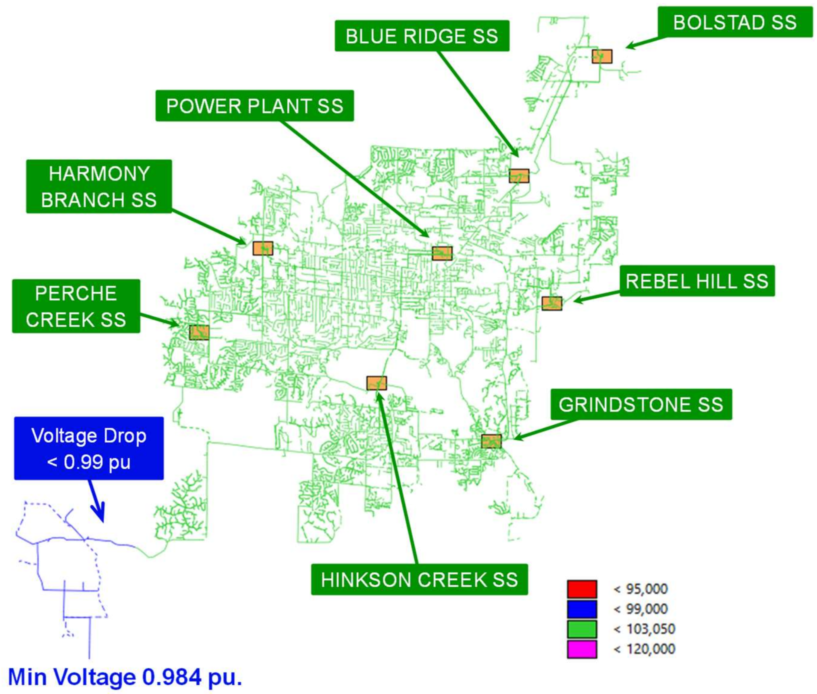


Figure 5-11 Voltage check in 2030 feeder peak load condition

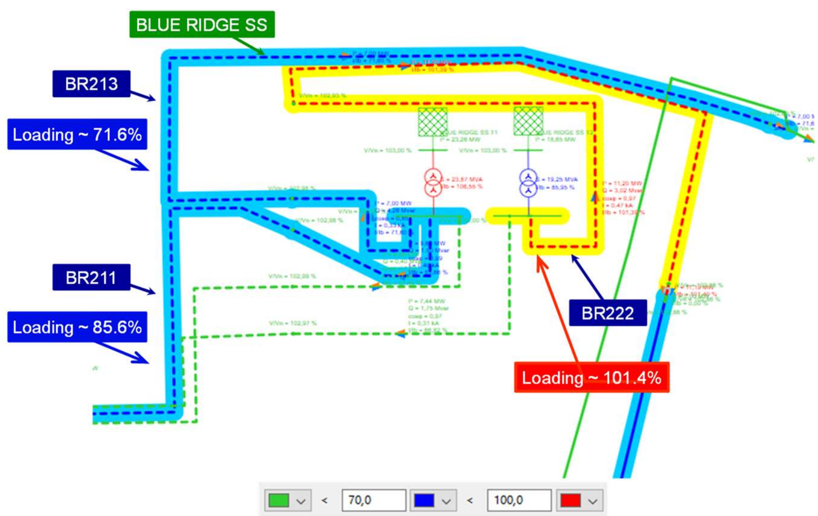


Figure 5-12 Loading violation of BR222 substation exit in 2030 feeder peak load condition

The overview of loading check for the entire system is shown below.

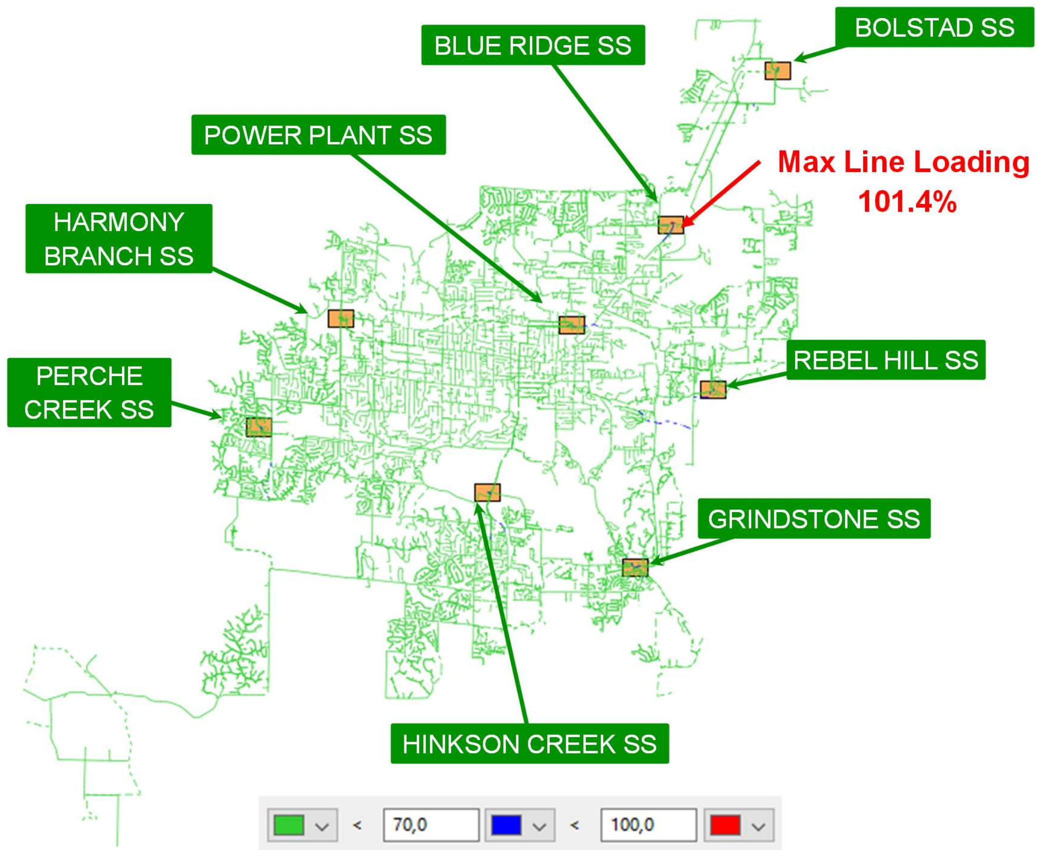


Figure 5-13 Loading check in 2030 feeder peak load condition

5.4.4 System analysis under 2040 Feeder Peak Load Conditions

As described before, water treatment area supplied by PC221 feeder has voltage violations. The lowest voltage was detected in PC221 (98.2%), shown in blue in Figure 5-14.

With respect of the loading in 2040 feeder peak load condition, loading issues become more severe. Most of loading violations was appeared in small sections located the substation exits. Maximum line loading was 121.4 % at the substation exit of BR222 as shown in Figure 5-15. In addition to that, HC211, GS222, RH212, BD222 substation exists show loading violations as shown in Figure 5-16. These overloads will be addressed together with the overloads identified under emergency conditions

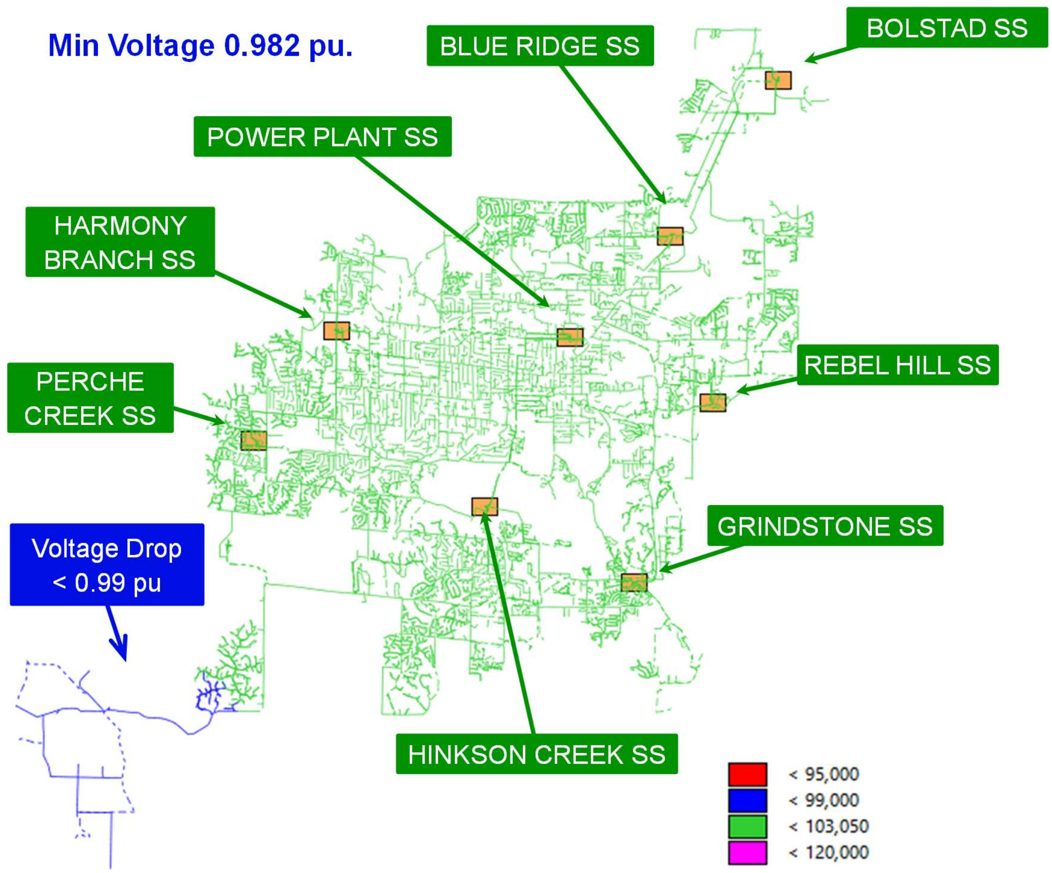


Figure 5-14 Voltage check in 2040 feeder peak load condition

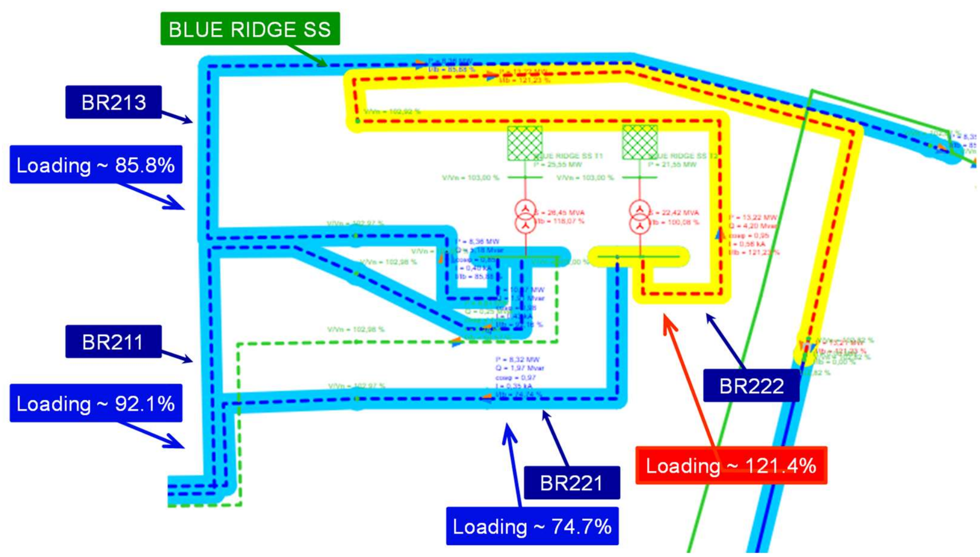


Figure 5-15 Loading violation of BR222 substation exit in 2040 feeder peak load condition

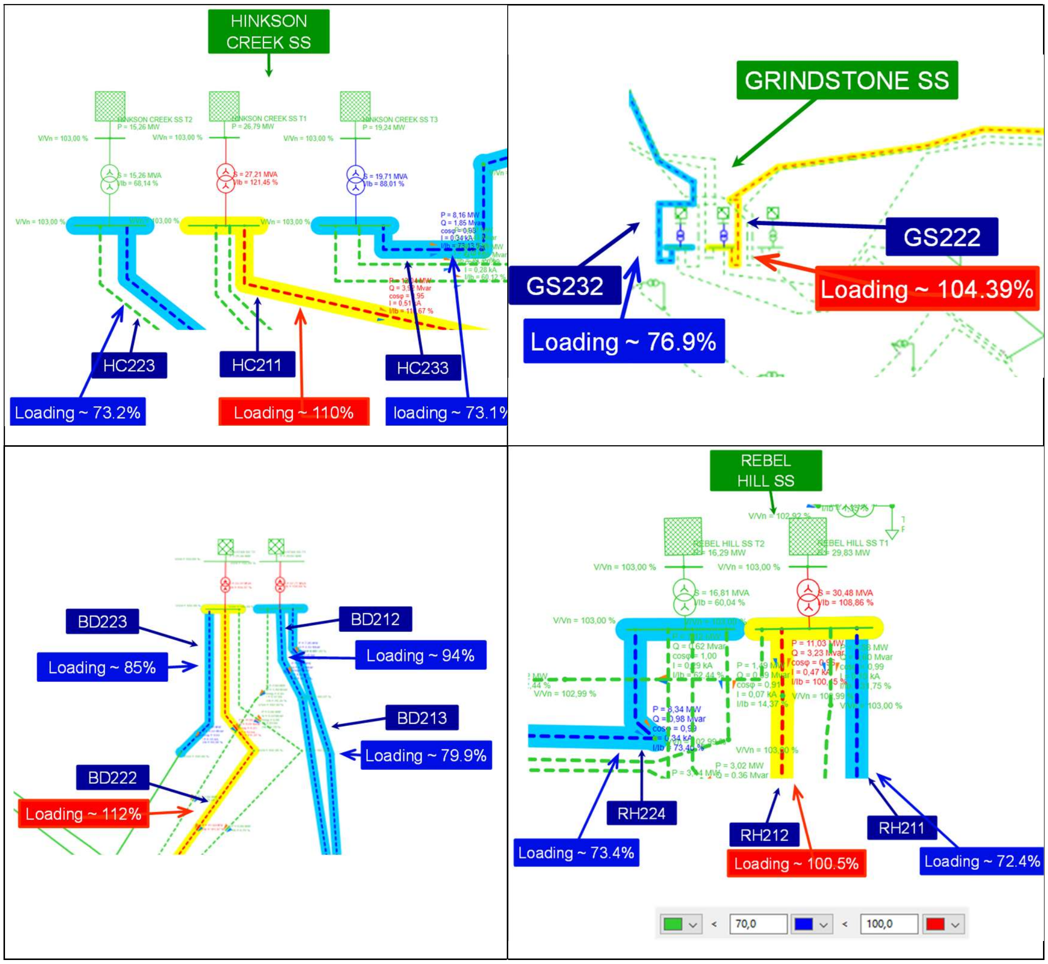


Figure 5-16 Loading violation of HC211, GS222, BD222 and RH212 substation exits in 2040 feeder peak load condition

5.5 Distribution Network Analysis under emergency conditions

5.5.1 Distribution Planning Procedure

Distribution planning is not a straightforward process by its nature is very granular, particularly for the analysis emergency (n-1) conditions and can be an extensive and iterative procedure as the same solutions may need to address various conditions identified along the process.

The procedure as listed below is followed in this study.

1. Selection of planning area and related feeders
2. Assessment of existing feeder performance for each planning term (2025, 2030 and 2040) under normal and emergency conditions and identification of violations
3. Reconfiguration (load transfers) and switching strategy considered as the first approach to address violations and if not possible determination of reinforcements.

4. Determination of proposed capacitors additions to manage voltage and power factor.
5. Verification of solutions over each planning term (2025, 2030 and 2040)
6. If required, repeat the procedure iteratively until solution is verified.
7. Summary of investments

5.5.2 Distribution Network Performance and Identification of Solutions

As the distribution system is designed taking advantage of the substations that supply it, the results of the analysis are presented by "areas" instead by single substation or feeder.

5.5.2.1 Area 1 – Blue Ridge and Bolstad Area

The Area 1 is shown in Figure 5-17 and includes the following feeders:

- From Blue Ridge: BR221
- From Bolstad: BD212 and BD223

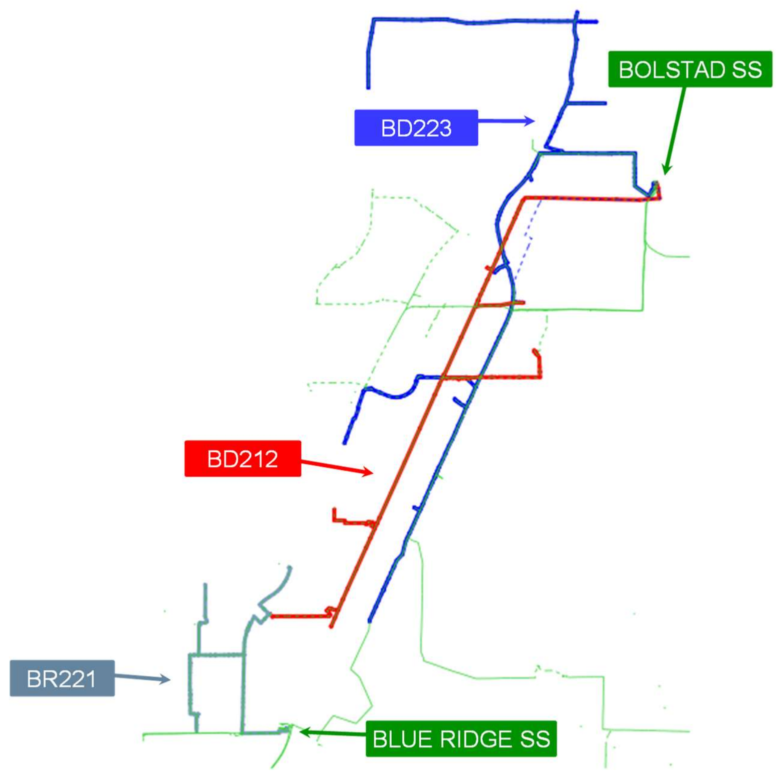


Figure 5-17 Supply area of associated feeders in Area 1

The load at these feeders is shown in Table 5-4 considering the current configuration. This load is under normal conditions and not accounting for any load transfers

Table 5-4: Feeder loads of Area 1 before any transfer or investment

Feeder	2020 P [MW]	2025 P [MW]	2030 P [MW]	2040 P [MW]
BR221	1.64	1.61	1.61	1.80
BD212	4.43	5.85	6.99	9.43
BD223	4.63	5.09	6.26	9.11

Considering the current configuration, BD212 and BR221 feeders can be transferred to each other during emergency conditions without any overloading or voltage violation in 2025, 2030 and 2040. Although BD223 can be transferred to BR213 in 2025 and 2030 without any voltage or loading violation, this would not be possible with the 2040 forecasted loads as BR213 substation exit would be overloaded to 109.1% and Blue Ridge Substation T1 would be overloaded to 111.91% as shown in Table 5-5 and Figure 5-18.

Table 5-5: Overloading violation under BD223 emergency condition in 2040

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Bolstad	BD223	BR213	-	109.1%	99.9%	2040

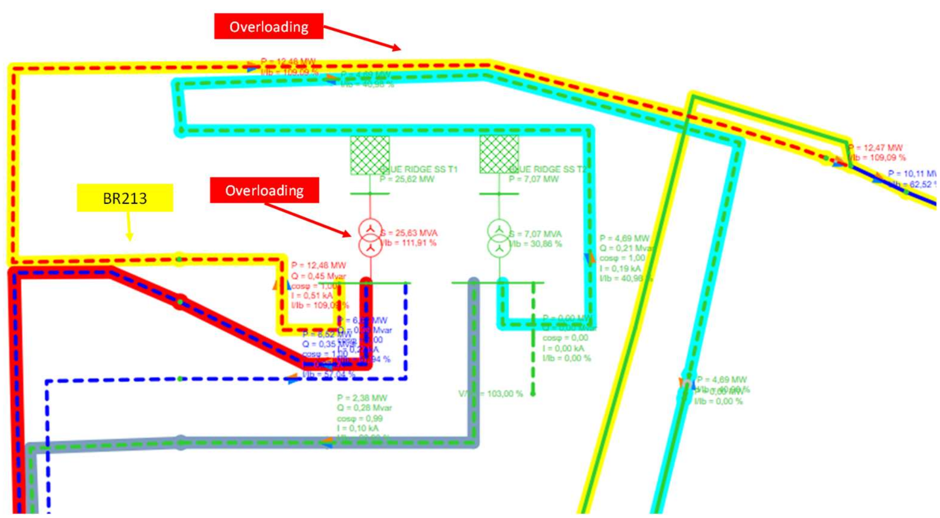


Figure 5-18 Overloading violation under BD223 emergency condition in 2040

To address the above, a short connection (Project 1, 500 kcmil CU – 0.227 mi) between BR221 and BD223 is proposed (see Figure 5-19). With the new connection, BD223 can be backed up by BR221. The new connection would be necessary by 2040 if it were only for BD223 emergency. However, when we considered the need to provide backup to feeder BD213 (see Area 2 below) it was identified that this investment it should be done by 2025.

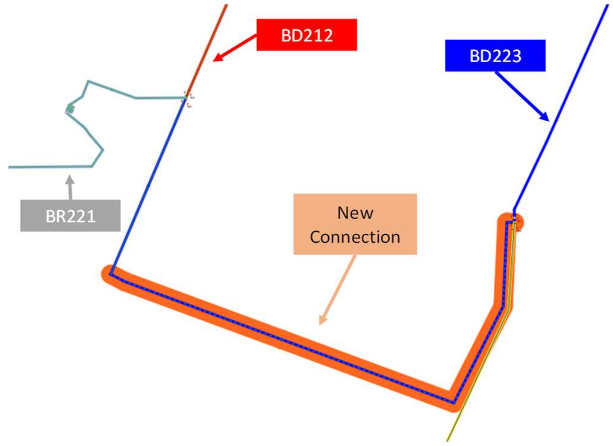


Figure 5-19 Project 1 - New connection between BR221 and BD223

With the new section addition above, only minor supply area reconfiguration is required to simplify network operation and reducing the loading of the Blue Ridge Substation T1 as shown below.

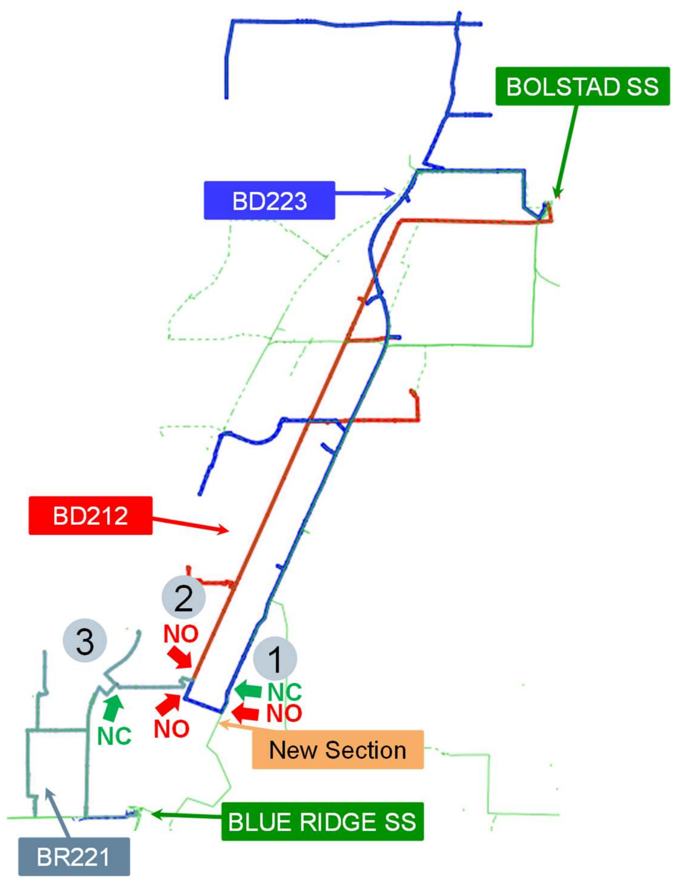


Figure 5-20 Project 1 - New connection between BR221 and BD223

After reconfiguration of feeder supply areas, the new loads for the feeders are shown in Table 5-6.

Table 5-6: Feeder loads of Area 1 after the investment and load transfer

Feeder	2025 P [MW]	2030 P [MW]	2040 P [MW]
BR221	1.95	2.02	2.38
BD212	5.25	6.32	8.15
BD223	5.34	6.50	9.76

New capacitor banks are proposed to improve power factor at various locations. They are sized considering the preference to prevent injection of reactive power at the substation back to transmission. They are listed in Table 5-7 according to sizes and years of installation. Location of capacitor banks is shown in Figure 5-21.

Table 5-7: New capacitor banks for Area 1

Feeder Name	2025 900 kVAr	2030 600 kVAr	300 kVAr	2040 600 kVAr	900 kVAr
BR221	-	-	-	-	-
BD212	-	-	-	-	1
BD223	1	1	1	3	-

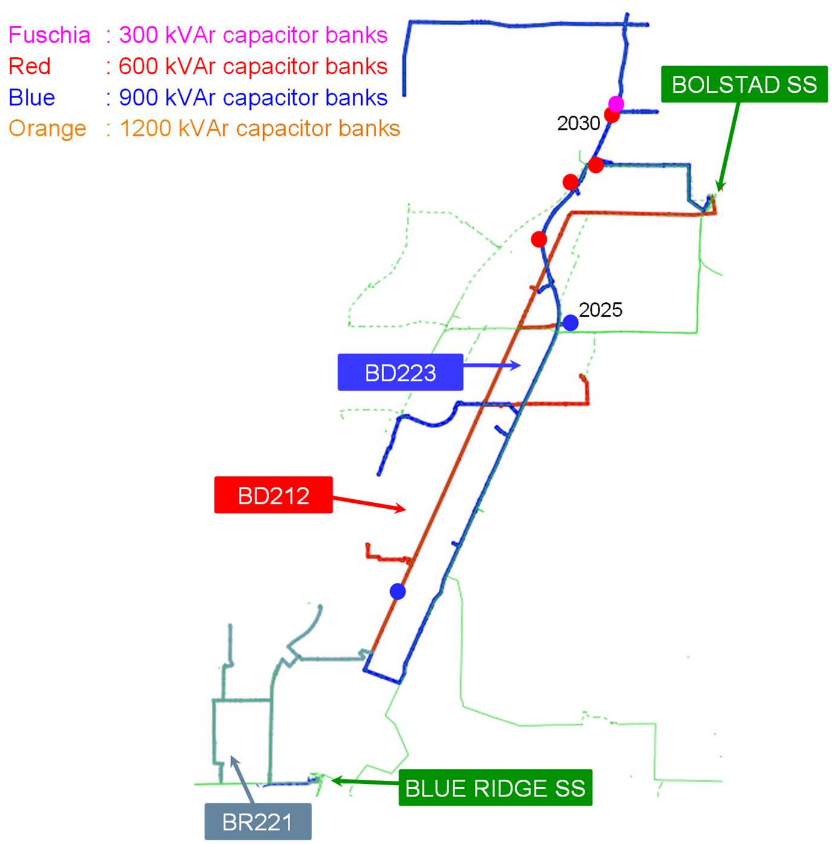


Figure 5-21 New capacitor banks in Area 1

The reinforced proposed system was analyzed under emergency conditions. Table 5-8 summarizes for feeders BD212, BD223 and BR221 what is the recommended backup feeder(s) for each term. These back up feeders can accept all load from main feeder (with the contingency) without loading or voltage violations.

Table 5-8: Back-up feeders of Area 1 for each term

Substation	Main Feeder	2025		2030		2040	
		Back-Up Feeder-1	Back-Up Feeder-2	Back-Up Feeder-1	Back-Up Feeder-2	Back-Up Feeder-1	Back-Up Feeder-2
Bolstad	BD212	BR221	-	BR221	-	BR221	-
Bolstad	BD223	BR221	-	BR221	-	BR221	BD212
Blue Ridge	BR221	BD212	-	BD212	-	BD212	-

5.5.2.2 Area 2 – Bolstad Area

The Area 2 is shown in Figure 5-22 and includes the feeders only feeders from this substation

- From Bolstad: BD211, BD213, BD221, BD222

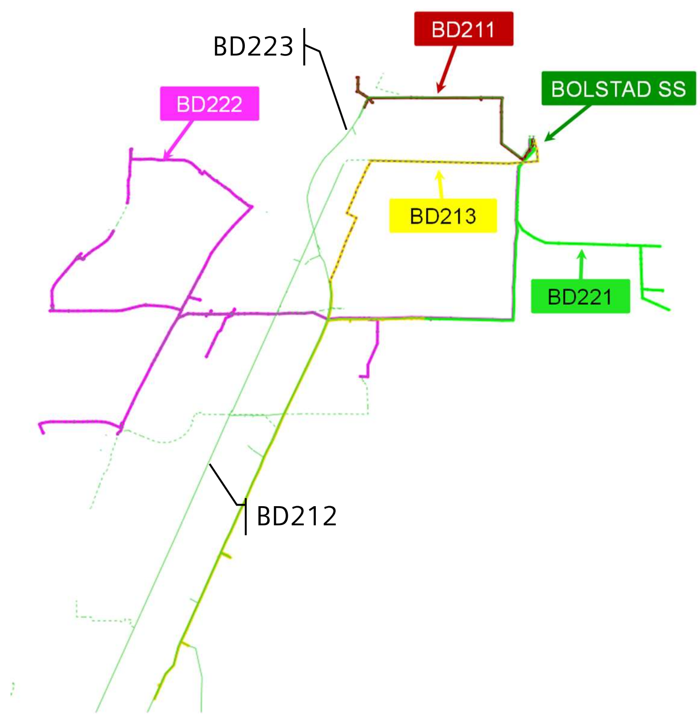


Figure 5-22 Supply area of associated feeders in Area 2

The load at these feeders is shown in Table 5-9 considering the current configuration. This load is under normal conditions and not accounting for any load transfers

Table 5-9: Feeder loads of Area 2 before any transfer or investment

Feeder	2020 P [MW]	2025 P [MW]	2030 P [MW]	2040 P [MW]
BD213	5.37	5.51	6.45	7.95
BD211	1.99	1.95	1.88	2.69
BD221	0.72	0.71	0.68	0.66
BD222	5.84	7.40	9.01	11.69

With the current configuration, only BD221 feeder can be transferred to BD213 during emergency without overloading or voltage violation in 2025, 2030 and 2040.

BD222 has 7.40 MW load in 2025 and it forecasted to grow to 9.01 and 11.69 MW respectively by 2030 and 2040. As discussed earlier with this loading BD222 would be overloaded by 2040 under normal condition. Its backup is also an issue, BD223 discussed earlier was considered as an possibility. However, when BD222 is transferred to BD223, the first section out of the substation exit would be overloaded under 2025 conditions and there would be voltage violations along the feeder as 98.1% even though in 2025 as shown Table 5-10 and Figure 5-23.

Table 5-10: Violations under BD222 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	First Year
Bolstad	BD222	BD223	-	116.8%	98.1%	2025

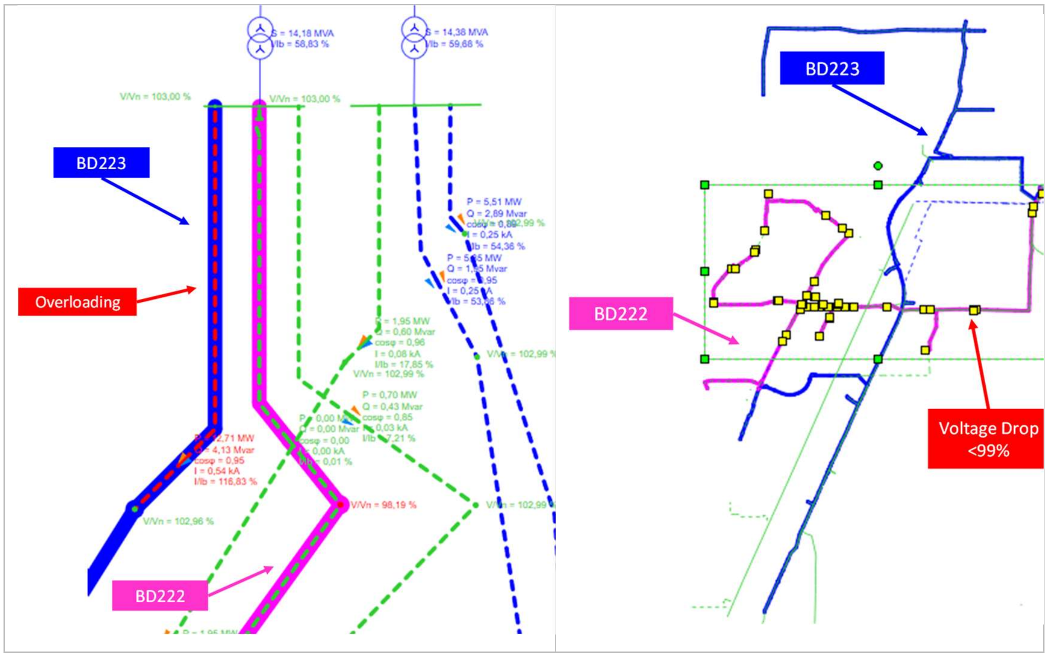


Figure 5-23 Overloading and Voltage violation with BD222 being transfer to BD223 under emergency condition in 2025

To address this a new feeder BD231_ST (Project 4, 500 kcmil CU – 1.132 mi) is proposed by 2025 to take some of the load of BD222 and connect to the new transformer proposed for Bolstad. BD231_ST can take BD222 load during emergencies without any voltage or loading violation in 2025 and 2030. By 2040, BD231_ST substation exit would be overloaded to 101.5% under this condition. BD212 would take some load from DB222 to address this loading issue in emergency.

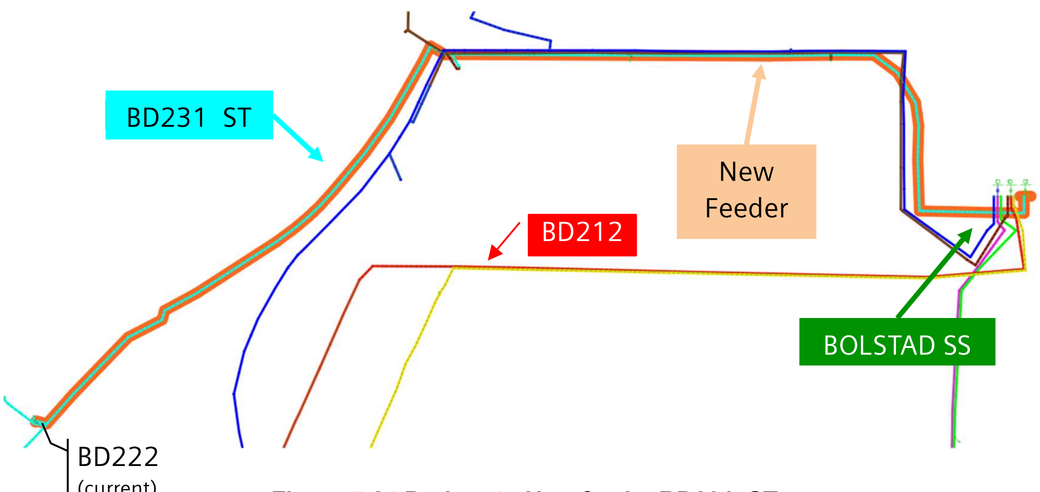


Figure 5-24 Project 4 - New feeder BD231_ST

Under an emergency, BD211 can be transferred to BD223 in 2025 and 2030 without any overloading or voltage issue. However, BD223 substation exit would become overloaded when providing backup to BD211 under 2040 conditions as shown in Table 5-11 and Figure 5-25.

Table 5-11: Violations under BD211 emergency condition in 2040

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Bolstad	BD211	BD223	-	109.1%	101.2%	2040

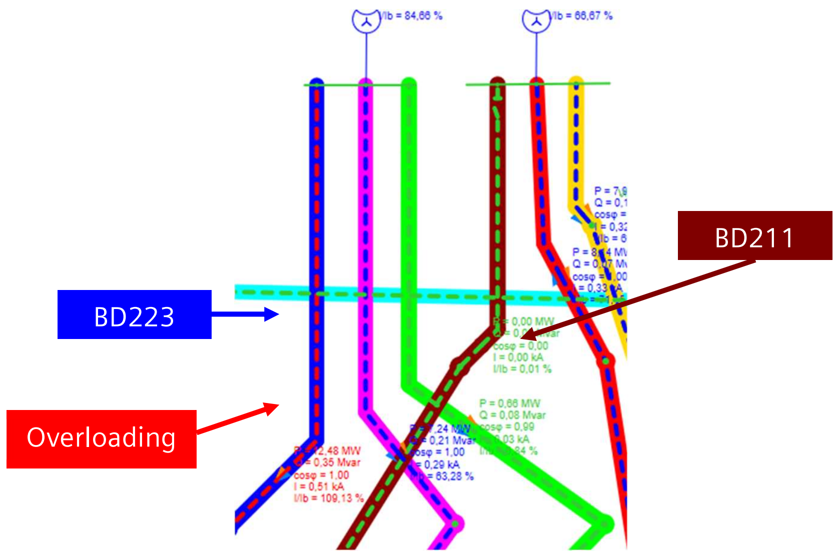


Figure 5-25 Overloading violation under BD222 emergency condition in 2040

BD223 substation exit could be doubled by 2040 to address this issue. Instead of that, a short connection between BD231_ST and BD211 (Project 2, 500 kcmil CU - 0.012 mi) is proposed to solve this issue in 2025, since this connection also provides a backup for the lateral which has 1.68 MW in 2025. The new connection is shown in Figure 5-26.

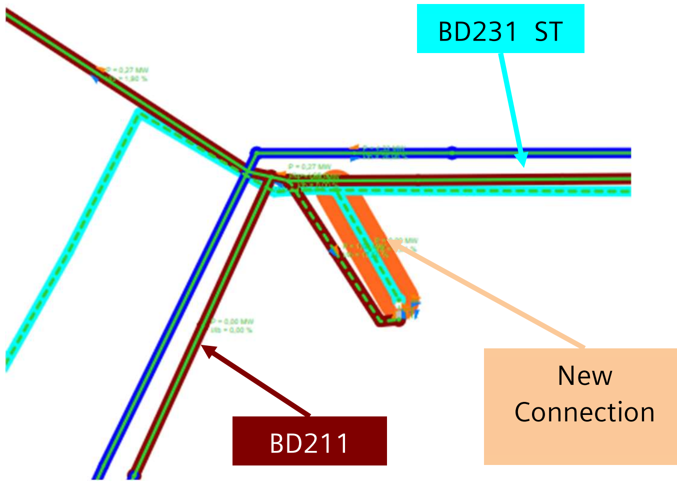


Figure 5-26 Project 2 - New connection between BD211 and BD231_ST

The New feeder RH232_ST discussed later in this document, was considered to create a backup for BD213. However, once BD213 is transferred to RH232_ST there would be a voltage drop at the end of the feeder (98.8%) as shown in Table 5-12 and Figure 5-27.

Table 5-12: Violations under BD213 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Bolstad	BD213	RH_232_ST	-	74.5%	98.8%	2025

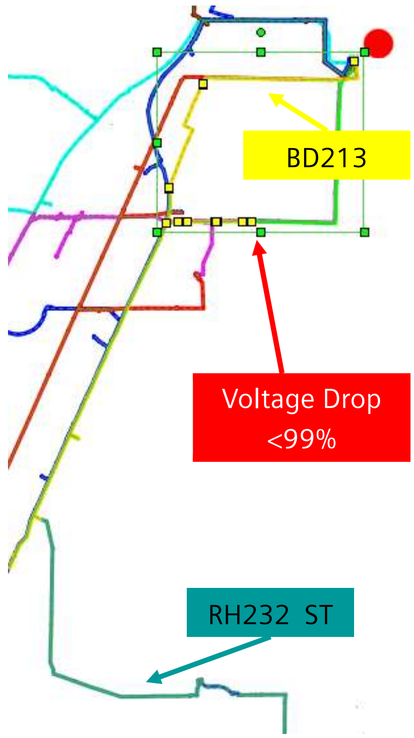


Figure 5-27 Voltage violation under BD213 emergency condition in 2025

We propose instead a short connection between BD223 and BD213 (Project 3, 500 kcmil CU - 0.002 mi) at BD213 feeder end. This connection provides a route to connect BR221 and BD213 using Project 1 that creates a connection between BD223 and BR221 and as indicated earlier is required by 2025 as well. After switching, BR221 can supply BD213 in emergency without any voltage or loading violation.

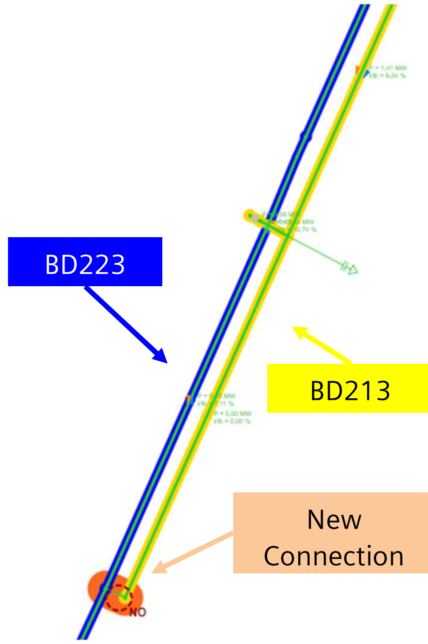


Figure 5-28 Project 3 - New connection between BD223 and BD213

With the investments identified above and the associated changes in the supply areas as shown in Figure 5-29, the new loads for the feeders are as in Table 5-13 below.

Table 5-13: Feeder loads of Area 2 after the investment and load transfer

Feeder	2025 P [MW]	2030 P [MW]	2040 P [MW]
BD213	5.50	6.44	7.92
BD211	1.95	1.88	2.69
BD221	0.71	0.68	0.66
BD222	5.06	5.85	7.24
BD231_ST	2.30	3.09	4.30

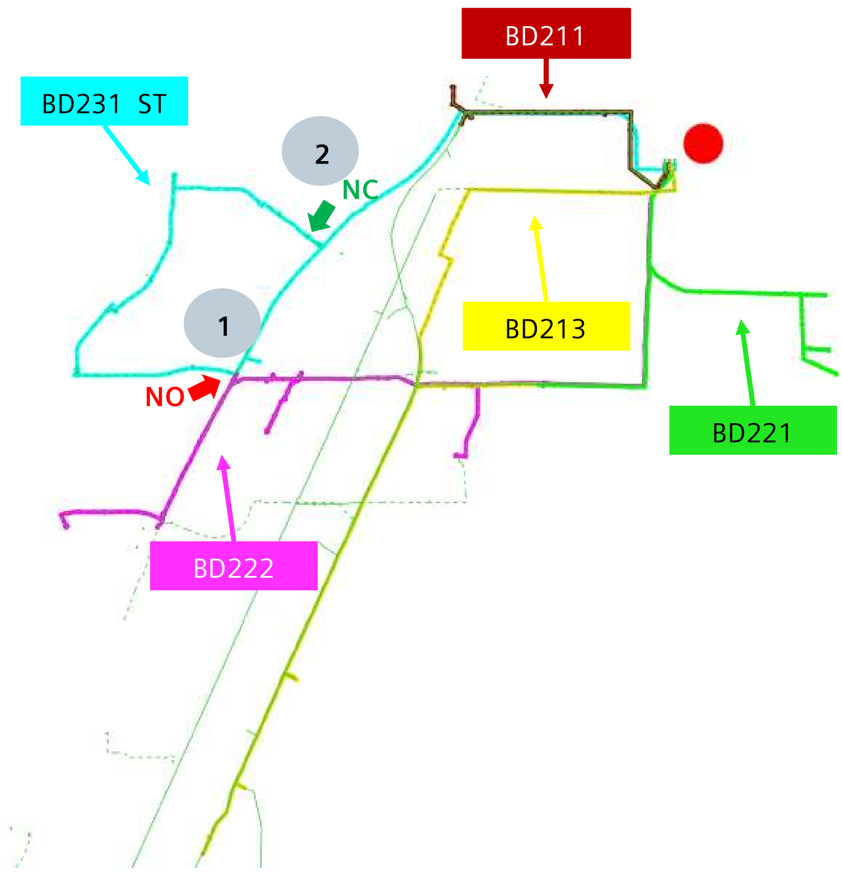


Figure 5-29 Proposed supply area for Area 2 in 2025

New capacitor banks are proposed to improve power factor at various locations. They are sized avoiding the injection of reactive power at the substation back to transmission. The proposed capacitor banks are listed in Table 5-14 that shows sizes and in service years. Additionally, the location of capacitor banks is shown in Figure 5-30.

Table 5-14: New capacitor banks for Area 2

Feeder Name	2025				2030		2040		
	300 kVAr	600 kVAr	900 kVAr	1200 kVAr	300 kVAr	600 kVAr	300 kVAr	600 kVAr	900 kVAr
BD213	-	1	1	1	-	1	-	-	1
BD211	-	-	-	-	-	-	1	-	-
BD221	1	-	-	-	-	-	-	-	-
BD222	-	-	-	-	-	-	-	-	-
BD231_ST	-	1	-	-	1	-	-	1	-

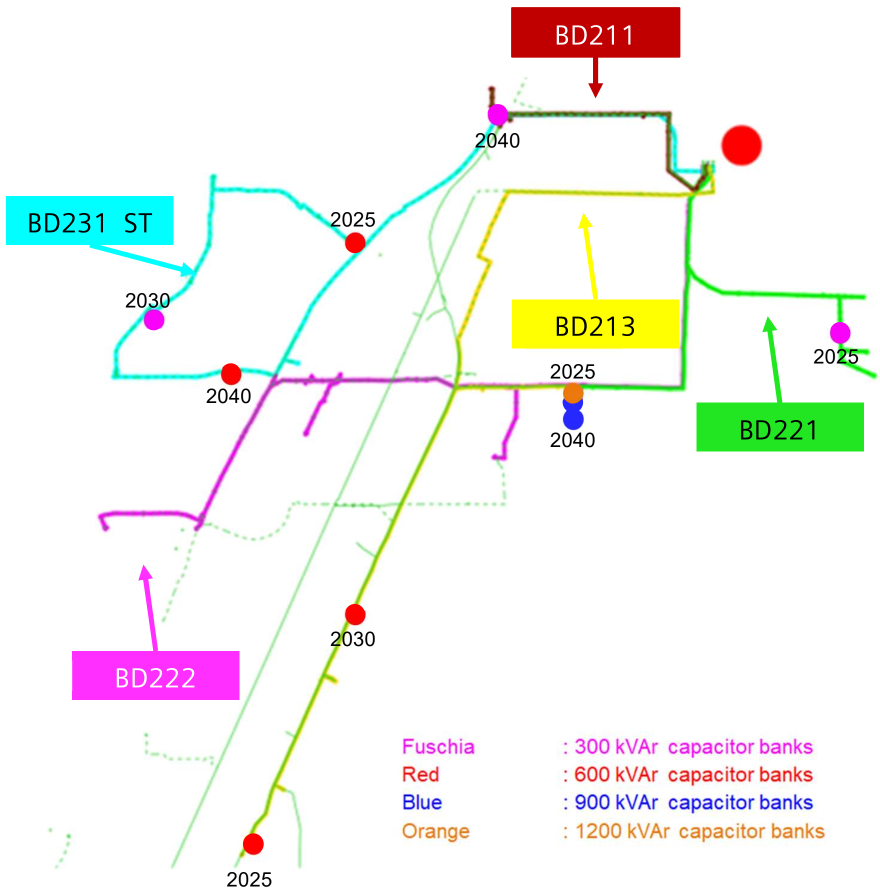


Figure 5-30 New capacitor banks in Area 2

The reinforced proposed system was analyzed under emergency conditions. Table 5-15 summarizes for feeders BD211, BD213, BD221, BD222 and BD231_ST what is the recommended backup feeder(s) for each term. These back up feeders can accept all load from main feeder (with the contingency) without loading or voltage violations.

Table 5-15: Back-up feeders of Area 2 for each term

		2025		2030		2040	
Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Back-Up Feeder-1	Back-Up Feeder-2	Back-Up Feeder-1	Back-Up Feeder-2
Bolstad	BD211	BD231_ST	-	BD231_ST	-	BD231_ST	-
Bolstad	BD213	BR221	-	BR221	-	BR221	-
Bolstad	BD221	BD213	-	BD213	-	BD213	-
Bolstad	BD222	BD231_ST	-	BD231_ST	-	BD231_ST	BD212
Bolstad	BD231_ST	BD222	-	BD222	-	BD222	BD212

5.5.2.3 Area 3 – Blue Ridge, Harmony Branch and Power Plant Area

The Area 3 is shown in Figure 5-31 and includes the following feeders.

- From Blue Ridge: BR212
- From Harmony Branch: HB211, HB213 and HB222
- From Power Plant: PP212

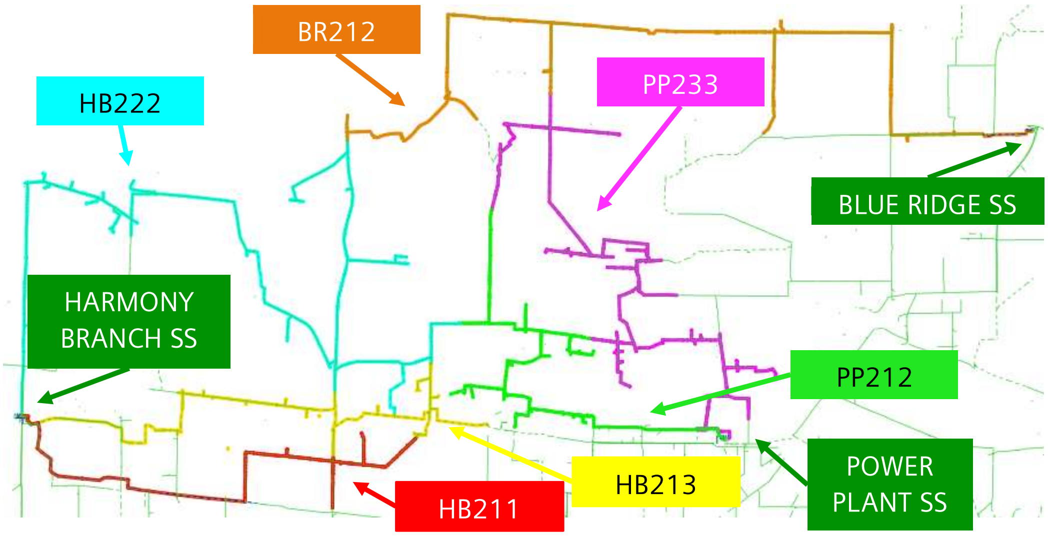


Figure 5-31 Supply area of associated feeders in Area 3

With the current configuration, the load at these feeders before any transfer is shown in Table 5-16.

Table 5-16: Feeder loads of Area 3 before any transfer or investment

Feeder	2020 P [MW]	2025 P [MW]	2030 P [MW]	2040 P [MW]
BR212	6.47	6.37	6.28	6.52
PP212	3.73	3.67	3.69	4.36
PP233	5.69	5.60	6.38	8.07
HB222	6.29	6.19	5.99	6.11
HB213	5.36	5.27	5.07	5.25
HB211	1.93	1.90	1.83	1.83

Although HB222 and PP233 feeders are adjacent feeders to BR212, they cannot provide a full back up to BR212. There would be overloading and voltage violations. Even partial back up is a problem due to voltage violations.

To provide a backup for BR212, PP212 supply area can be extended to create a connection between BR212 and PP212. When BR212 is supplied from PP212, the connection would be overloaded since lower conductor size (4/0) as shown in Figure 5-32. The connection should be upgraded to 500 kcmil CU (Project 5, 500 kcmil CU – 0.509 mi). After this reinforcement, BR212 can be transferred to PP212 largely and rest of load can be supplied from BR211 without any voltage or loading violation in any term.

Table 5-17: Violations under BR212 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Blue Ridge	BR212	PP212	-	114.1%	100.0%	2025

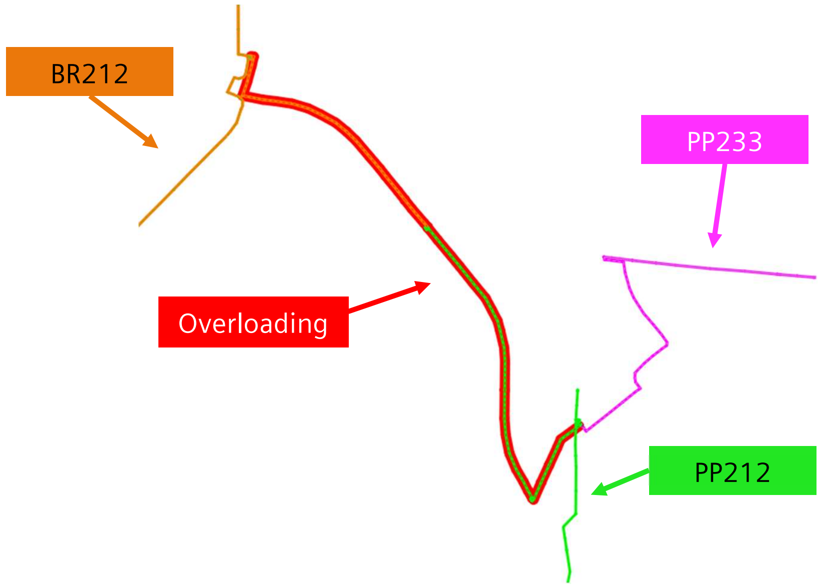


Figure 5-32 Overloading violation under BR212 emergency condition in 2025

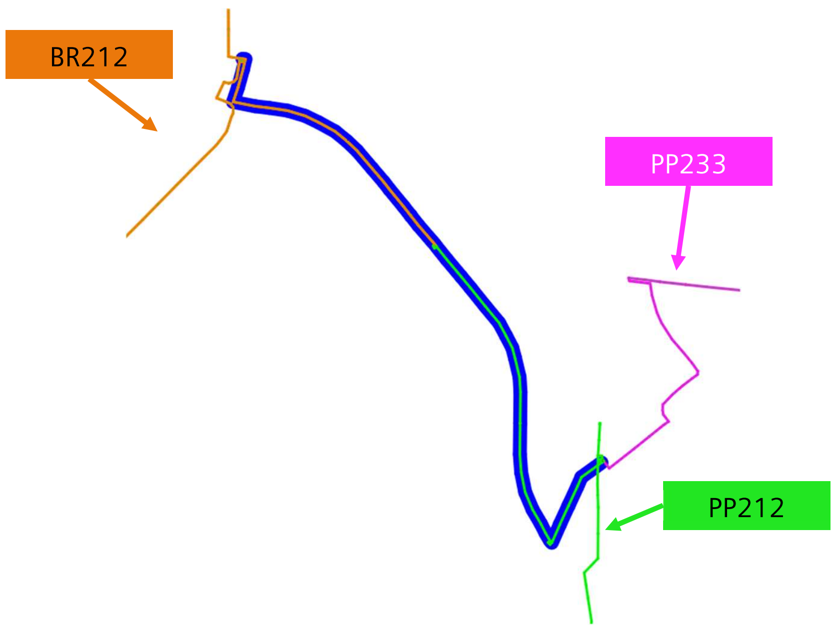


Figure 5-33 Project 5 - Reconductoring between BR212 and PP212

With the above, some of the load from PP233 is transferred to PP212 when creating the connection between BR212 and PP212.

With the current configuration, PP233 load could be transferred to PP212 only in 2025 without any loading or voltage violation. Starting from 2030, PP212 would not be able to receive all the load of PP233 as Power Plant T1 would be overloaded and BR211 should be considered as second backup feeder.

However, the emergency overloading of Power Plant T1 can be addressed by transferring load from PP214 to HB211. After this reconfiguration in supply areas, PP233 could be transferred to PP212 both in 2025 and 2030 without any loading or voltage violation. By 2040, BR211 should be used as second backup feeder to split the load.

HB222 has connections to HB213, BR212 and PP212. However, none of them could take HB222 load individually. If HB213 and PP212 took the load, there would be voltage violation along the feeder supplied from PP212 and loading violation Power Plant T1 in 2025. If HB213 and BR212 took the load, there would be minor voltage violation at the end of feeder supplied from HB213 which limits load transfer. Additionally, when HB213 is transferred to adjacent feeder PP214, Power Plant T1 would be overloaded.

To address the bottlenecks above affecting both HB222 and HB213, extending of HB211 supply area is proposed. HB211 has lower load than other feeders and has more room to provide back up. HB211 supply area is reconfigured by taking some load from HB222 and HB213 and a small amount from PP214. After reconfiguration of supply areas, HB222 and HB213 could be transferred to HB213 and HB211 respectively.

Reconfiguration of supply areas and related switching for Area 3 is illustrated in Figure 5-34. The new loads for the reconfigured feeders are shown in Table 5-18.

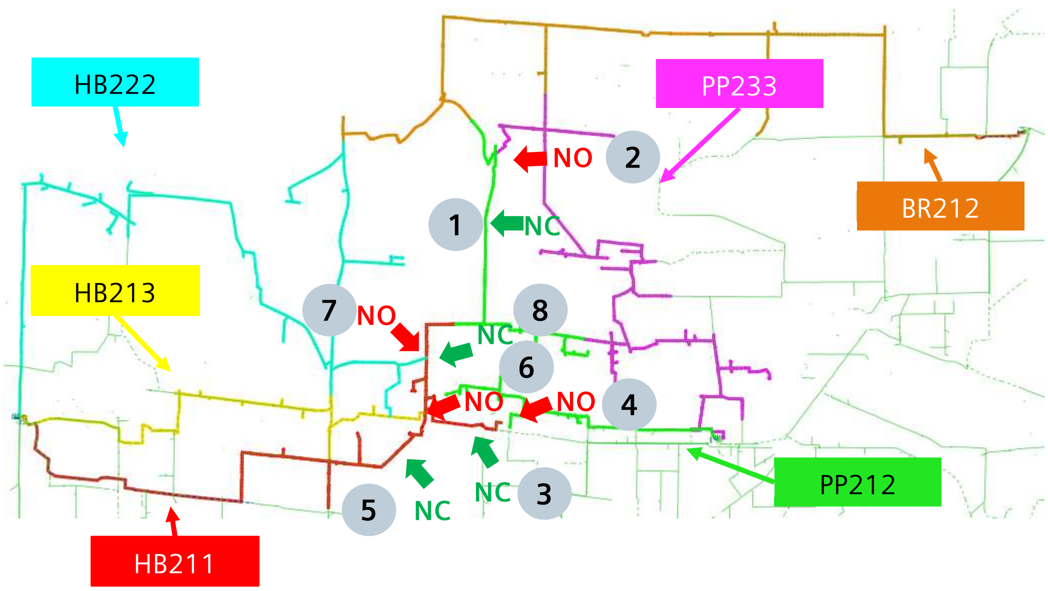


Figure 5-34 Proposed supply area for Area 3 in 2025

Table 5-18: Feeder loads of Area 3 after supply area reconfiguration

Feeder	2025 P [MW]	2030 P [MW]	2040 P [MW]
BR212	6.37	6.28	6.52
PP212	4.39	4.44	5.16
PP233	4.87	5.62	7.24
HB222	5.62	5.44	5.53
HB213	3.48	3.35	3.54
HB211	4.76	4.58	4.61

New capacitor banks are proposed to improve power factor at various locations. They are sized considering the preference to prevent injection of reactive power at the substation back to transmission. They are listed in Table 5-19 according to sizes. Additionally, location of capacitor banks is shown in Figure 5-35.

Table 5-19: New capacitor banks for Area 3

Feeder Name	2025 600 kVAr	2030 300 kVAr	2040 900 kVAr
BR212	-	-	-
PP212	-	-	-
PP233	1	1	1
HB222	-	-	-
HB213	-	-	-
HB211	-	-	-

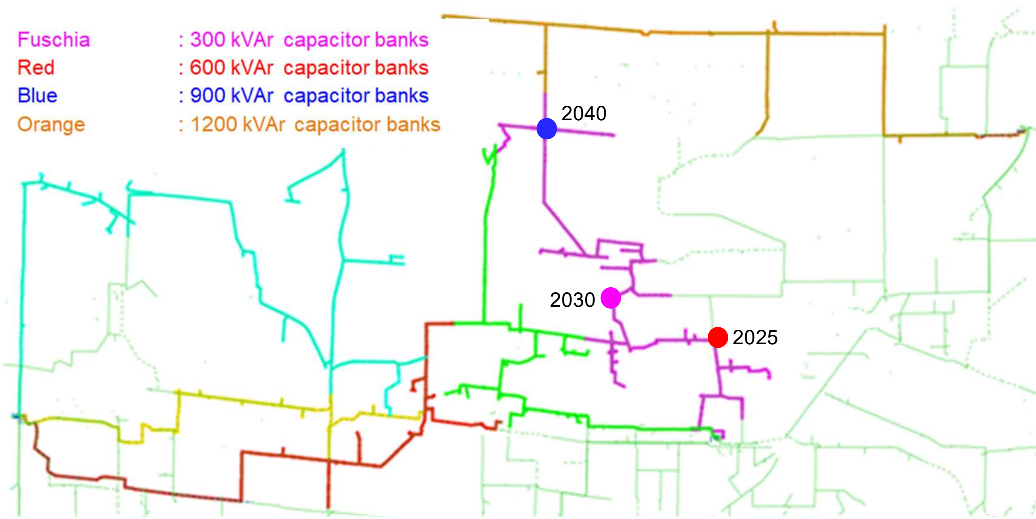


Figure 5-35 New capacitor banks in Area 3

The reinforced proposed system was analyzed under emergency conditions. Table 5-20 summarizes for feeders BR212, HB211, HB213, HB222, PP212 and PP233 what is the recommended backup feeder(s) for each term. These back up feeders can accept all load from main feeder (with the contingency) without loading or voltage violations.

Table 5-20: Back-up feeders of Area 3 for each term

Substation		2025		2030		2040	
	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Back-Up Feeder-1	Back-Up Feeder-2	Back-Up Feeder-1	Back-Up Feeder-2
Blue Ridge	BR212	PP212	BR211	PP212	BR211	PP212	BR211
Harmony Branch	HB211	PP212	-	PP212	-	PP212	-
Harmony Branch	HB213	HB211	-	HB211	-	HB211	-
Harmony Branch	HB222	HB213	-	HB213	-	HB213	-
Power Plant	PP212	HB211	-	HB211	-	HB211	-
Power Plant	PP233	PP212	-	PP212	-	PP212	BR211

5.5.2.4 Area 4 – Power Plant Area

The Area 4 is shown in Figure 5-31 and includes the feeders only feeders from Power Plant substation.

- Power Plant : PP214, PP221, PP223 and PP232

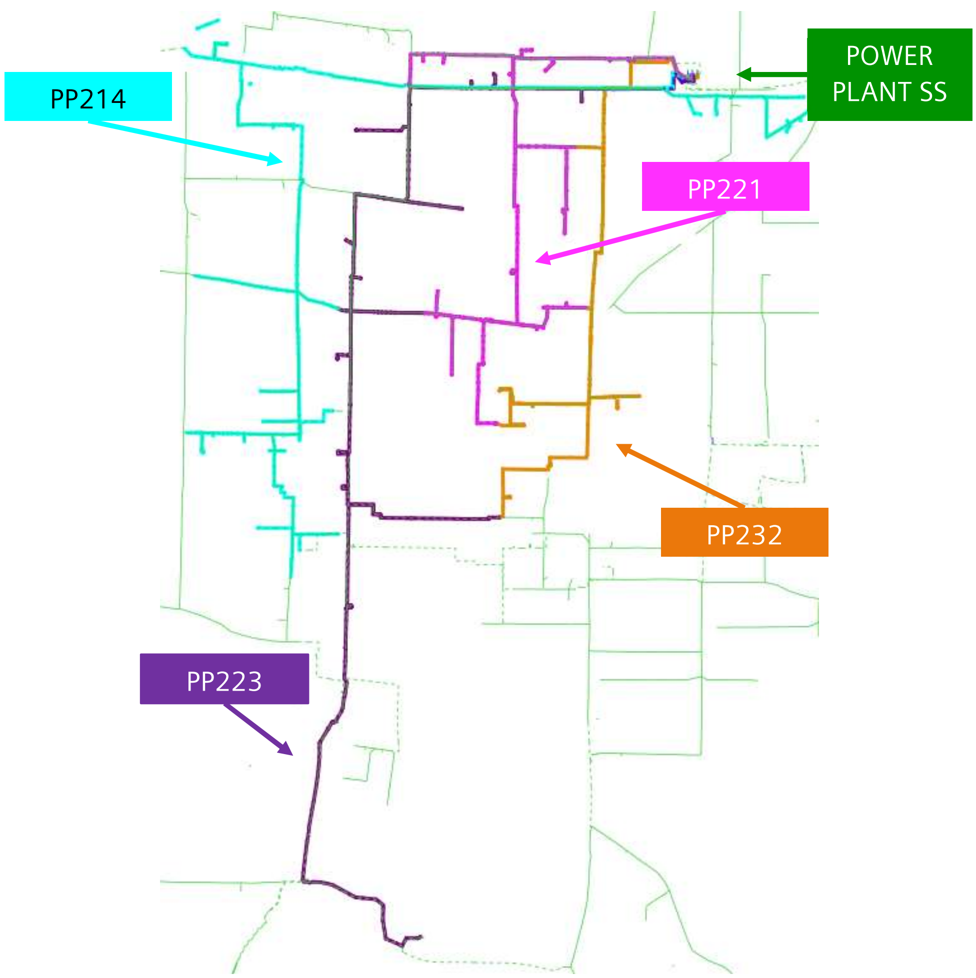


Figure 5-36 Supply area of associated feeders in Area 4

With the current configuration, the load at these feeders before any transfer is shown in Table 5-21.

Table 5-21: Feeder loads of Area 4 before any transfer or investment

Feeder	2020 P [MW]	2025 P [MW]	2030 P [MW]	2040 P [MW]
PP232	4.94	4.96	4.84	4.84
PP221	4.45	4.38	4.30	4.42
PP223	7.28	7.18	6.96	6.92
PP214	5.65	5.56	5.53	5.70

PP214 supply has connections with RH231_ST (a new feeder from Rebel Hill as presented later), HC233 and PP223. The best candidate to create back up is PP223 as by transferring some load to PP232 its load would be lower than the other feeders. Additional to the reconfiguration PP223 supply area, we observed that the connection between PP214 and PP223 is 4/0 which would be overloaded to 142.1% in 2025 when the PP214 load is transferred. Hence the existing 4/0 AL section should be reconductored to 500 kcmil CU (Project 6, 500 kcmil CU – 0.197 mi). After reconductoring, PP214 could be transferred to PP223 without any loading or voltage violation in each term.

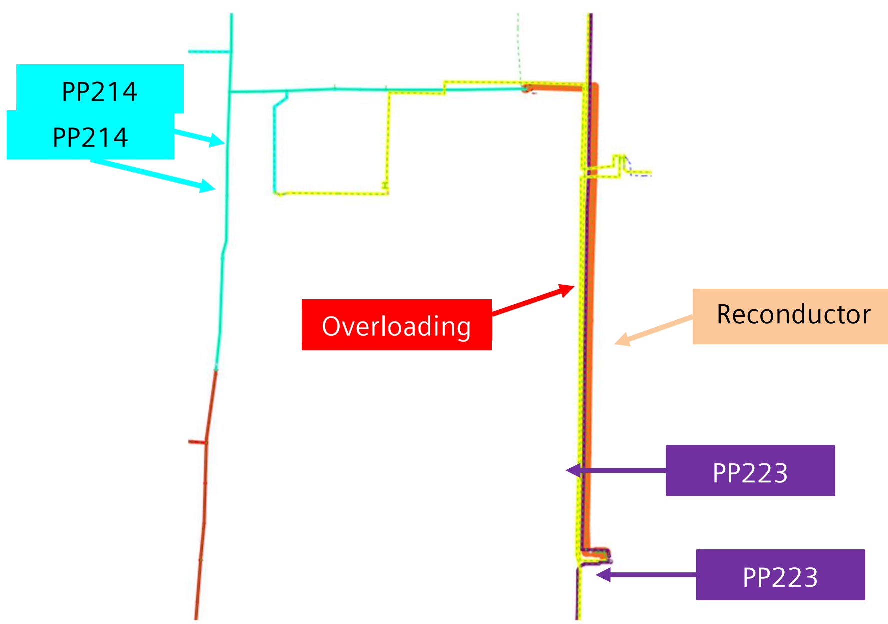


Figure 5-37 Project 6 - Reconductoring between PP214 and PP223

With the current configuration, once PP223 is transferred to PP232, there would be overloading at the substation exit by 2025 and Power Plant T3 would be overloaded in 2040. Therefore, some load of PP232 load is transferred to PP221 to create a room for emergency conditions. After this reconfiguration, PP223 could be transferred to PP232 without any overloading or voltage violation in 2025 and 2030. Although there would be no violation along the feeder in 2040, Power Plant T3 would be overloaded. Thus, PP221 should be second backup feeder in to PP223 by 2040 besides of PP232.

When PP232 is transferred to PP221, a short section would be overloaded to 168.9% in 2025 (see Table 5-22 and Figure 5-38). The same section would be overload when PP221 is transferred to PP232. Additionally, Power Plant T3 would be overloaded in 2040.

Table 5-22: Violations under PP232 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Power Plant	PP232	PP221	-	168.9%	101.3%	2025

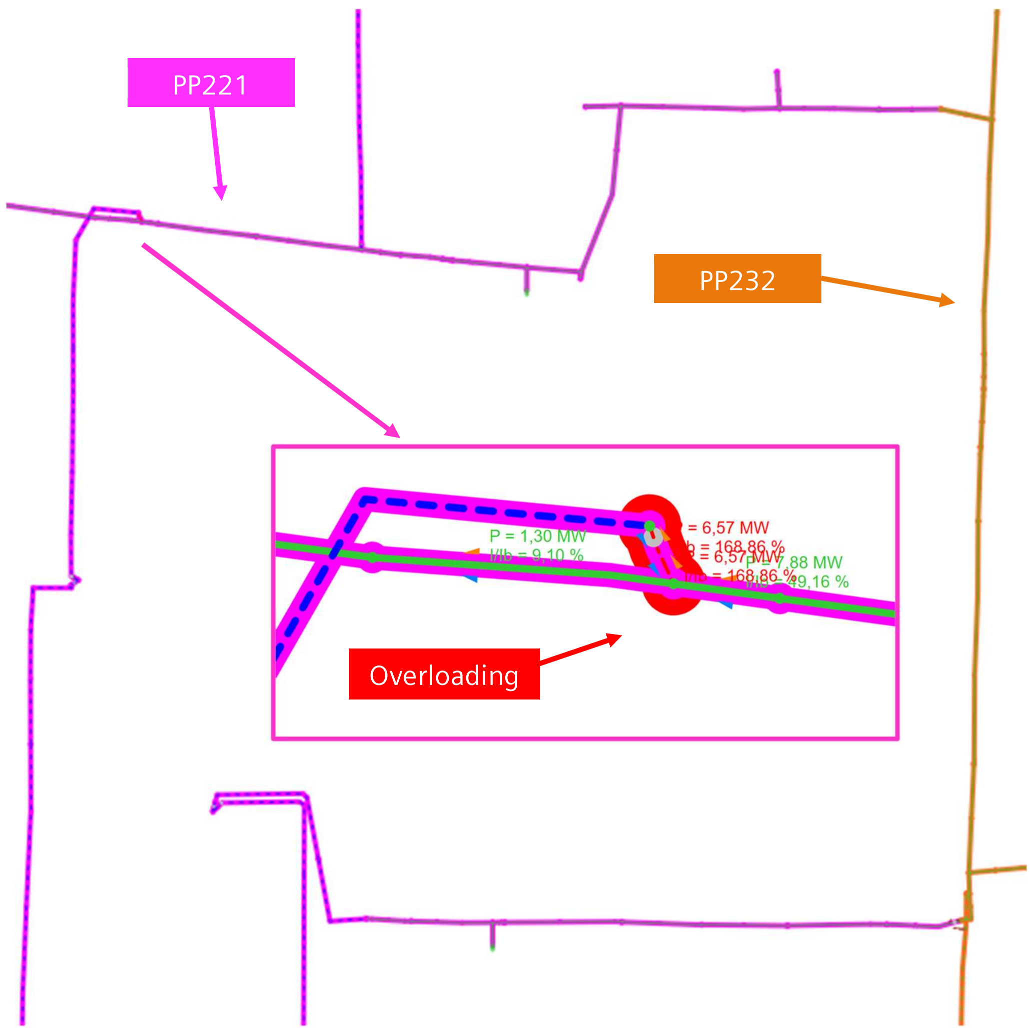


Figure 5-38 Overloading violation under PP232 emergency condition in 2025

To address the above, the existing 4/0 AL conductor should be upgraded. (Project 7, 500 kcmil CU – 0.003 mi). With this investment PP232 and PP221 can provide backup to each other in 2025 and 2030. In 2040, Power Plant T2 would be still overloaded to 102.2%. Thus, PP223 should be second backup feeder besides of PP232.

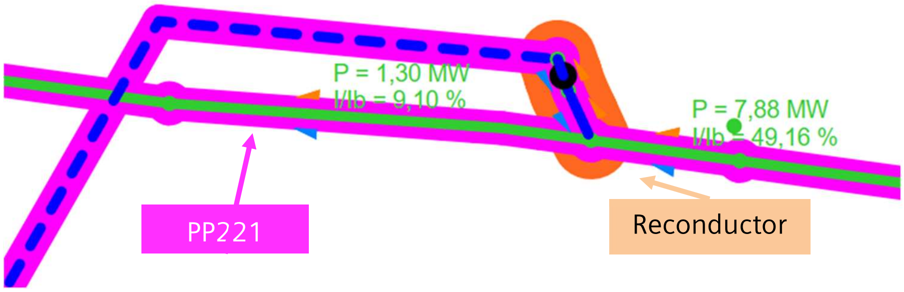


Figure 5-39 Project 7 - Reconductoring short section of PP221

Reconfiguration of supply areas and related switching for Area 4 is illustrated in Figure 5-40. The new loads for the associated feeders are shown in Table 5-23.

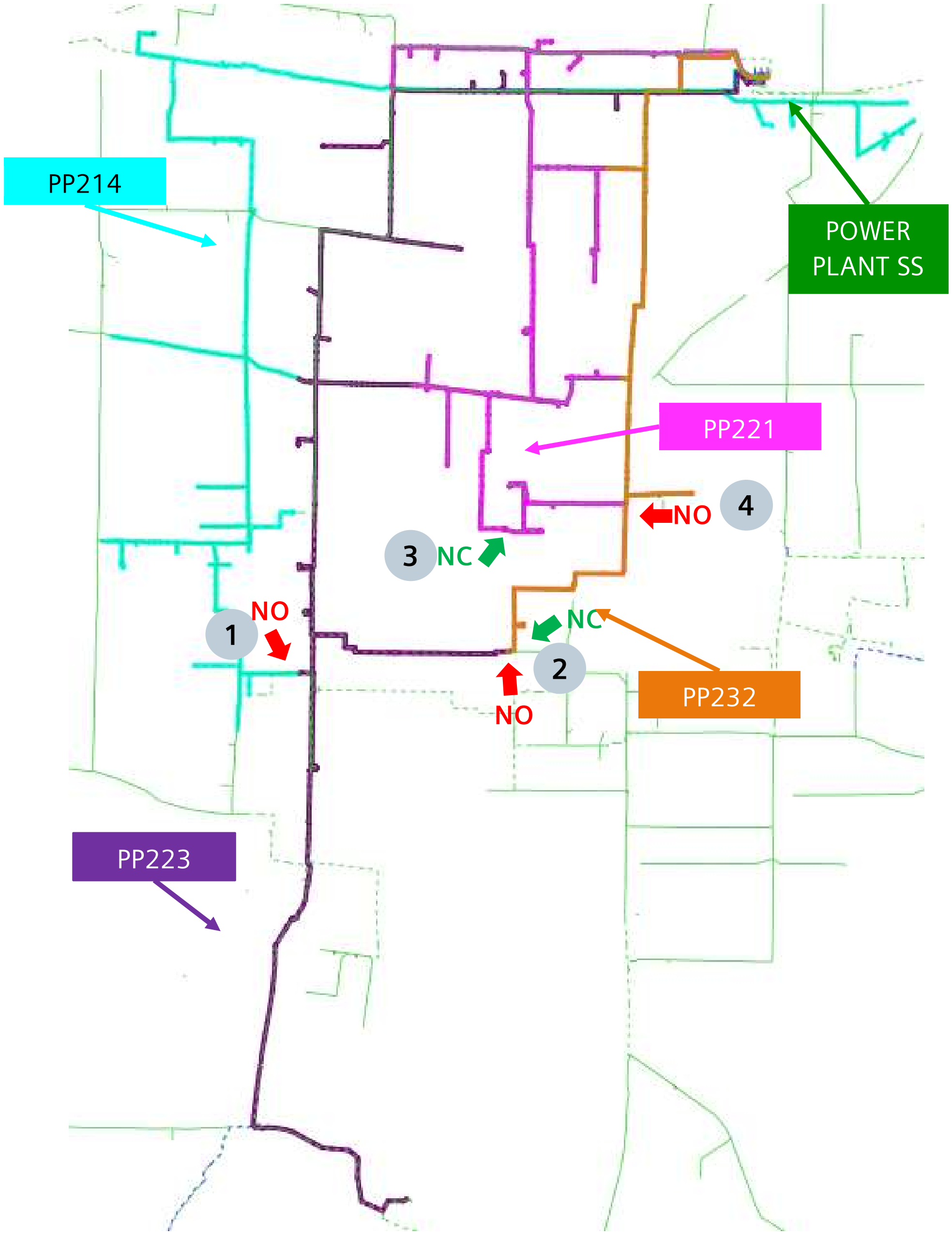


Figure 5-40 Proposed supply area for Area 4 in 2025

Table 5-23: Feeder loads of Area 4 after supply area reconfiguration

Feeder	2025 P [MW]	2030 P [MW]	2040 P [MW]
PP232	5.01	4.85	4.79
PP221	5.52	5.43	5.58
PP223	5.71	5.54	5.53
PP214	5.26	5.24	5.40

New capacitor banks are proposed to improve power factor at various locations. They are sized considering the preference to prevent injection of reactive power at the substation back to transmission. They are listed in Table 5-24 according to sizes, and in service date (2025). Additionally, location of capacitor banks is shown in Figure 5-41.

Table 5-24: New capacitor banks for Area 4

Feeder Name	2025 300 kVAr	2025 900 kVAr
PP232	1	-
PP221	-	-
PP223	-	2
PP214	-	1

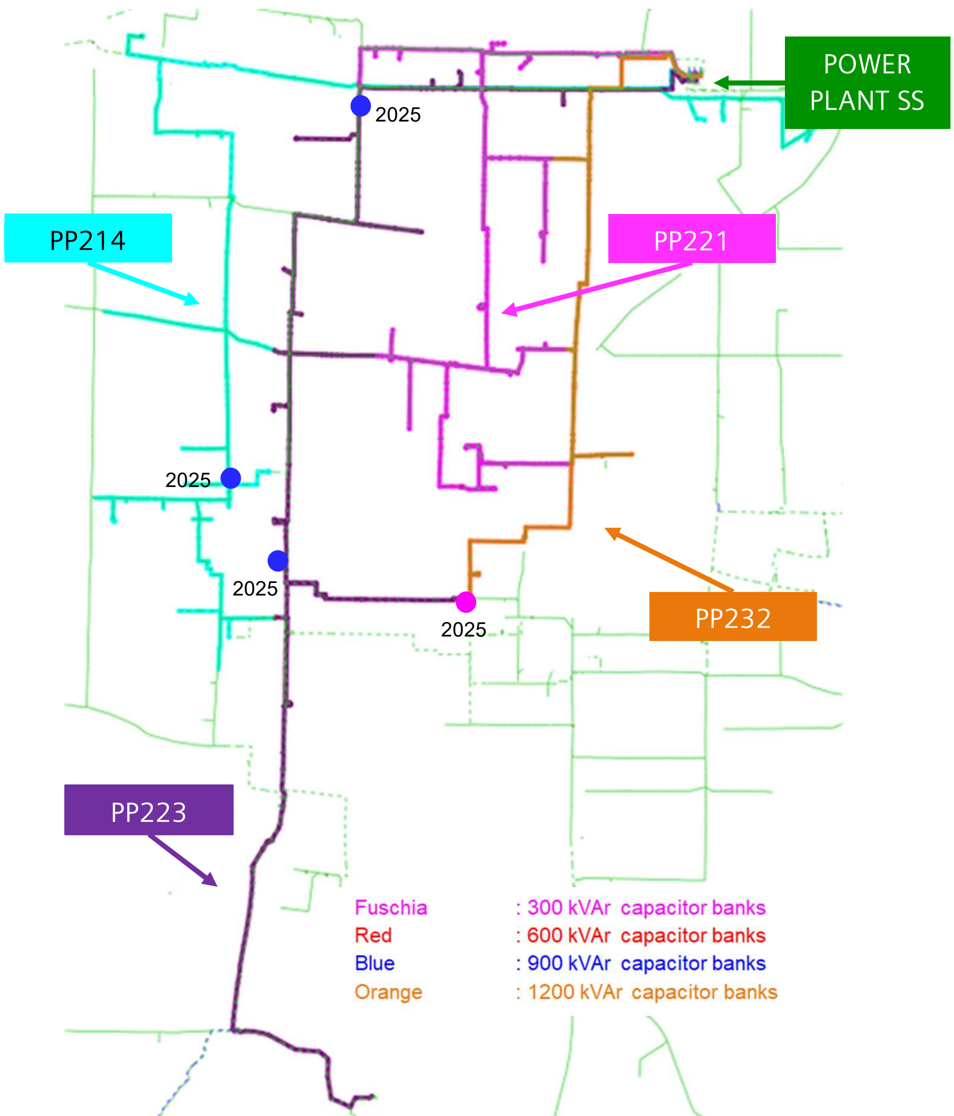


Figure 5-41 New capacitor banks in Area 4

The reinforced proposed system was analyzed under emergency conditions. Table 5-25 summarizes for feeders PP214, PP221, PP223 and PP232 what is the recommended backup feeder(s) for each term. These back up feeders can accept all load from main feeder (with the contingency) without loading or voltage violations.

Table 5-25: Back-up feeders of Area 4 for each term

Substation	Main Feeder	2025 Back-Up Feeder-1	2025 Back-Up Feeder-2	2030 Back-Up Feeder-1	2030 Back-Up Feeder-2	2040 Back-Up Feeder-1	2040 Back-Up Feeder-2
Power Plant	PP214	PP223	-	PP223	-	PP223	-
Power Plant	PP221	PP232	-	PP232	-	PP232	PP223
Power Plant	PP223	PP232	-	PP232	-	PP232	PP221
Power Plant	PP232	PP221	-	PP221	-	PP221	-

5.5.2.5 Area 5 – South of Perche Creek

The Area 5 is shown in Figure 5-42 and includes the feeder PC221 that supplies the water treatment facilities, the wastewater facilities, and a residential area.

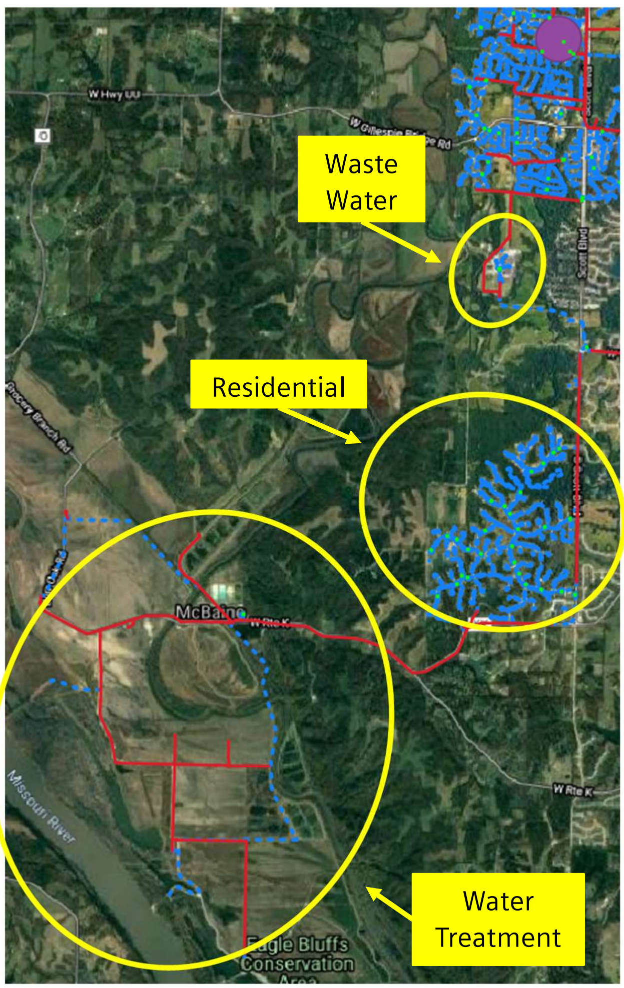


Figure 5-42 Supply area of associated feeders in Area 5

With the current configuration, the load at this feeder before any transfer is shown in Table 5-26.

Table 5-26: Feeder loads of Area 5 before any transfer or investment

Feeder	2020 P [MW]	2025 P [MW]	2030 P [MW]	2040 P [MW]
PC221	8.78	8.86	8.79	9.03

PC221 is the only feeder which has a voltage violation under normal condition starting from 2020 towards the water treatment facilities as this feeder is very long (10.6 mi) and supply approximately 9 MW load.

PC221 does not have a backup feeder as it is at the end of CWL service territory and there is no adjacent feeder. Additionally, the wastewater facility is supplied by two feeders PC221 and HC223. However, HC223 is overextended, and this load should be transferred to Perche Creek as the new recommended (third) transformer is placed service by 2025.

For this special area, both conventional and Non-Wire Alternative are considered to address the issues. The planning considerations for this area are shown below.

- There are 2x2 MW diesel generators, and they are sufficient to supply the water treatment area in case of interruption. There is no need to create additional backup for this area, but this generation cannot be used to provide emergency supply to the residential area.
- Loads in wastewater facility supplied from HC223 should be transferred to Perche Creek to relief Hinkson Creek transformer loading and utilizing new transformer to be installed at Perche Creek by 2025.
- PC221 has three types of loads as shown in Table 5-27.

Table 5-27: Details of PC221 loads

PC221	2025	2040
Total (Feeder Head)	8.86	9.03
Wastewater	2.8	2.64
Water Treatment	2	1.89
Residential	4.06	4.5

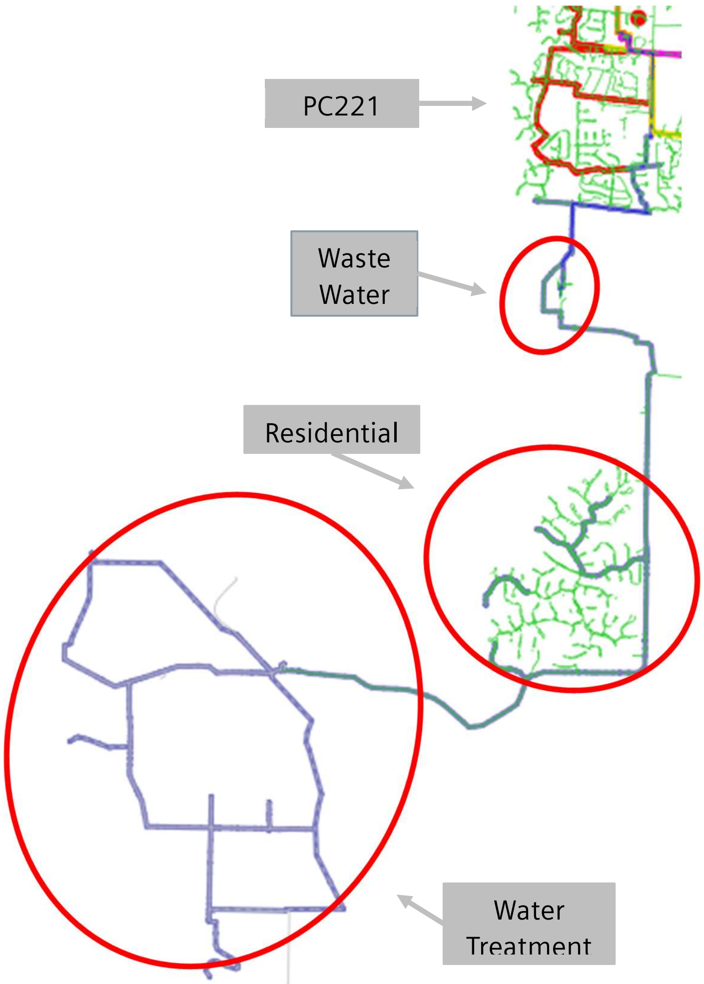


Figure 5-43 PC221 existing supply area

Considering conventional alternatives, a new feeder PC232_ST (Project 11 – Part 1, 500 kcmil CU – 2.28 mi) is proposed from Perche Creek. This new feeder will supply the wastewater loads originally served PC221 and HC223 and will be extended to provide backup for residential area with a new section (Project 11 – Part 2, 500 kcmil CU – 2.50 mi).

The reconfiguration of the supply areas, the required switching and new investments are illustrated in Figure 5-44. The new loads for the feeder are shown below

Table 5-28: Feeder loads of Area 5 after new feeder addition

Feeder	2025 P [MW]	2030 P [MW]	2040 P [MW]
PC221	5.63	5.68	5.98
PC232_ST	5.37	5.16	5.06

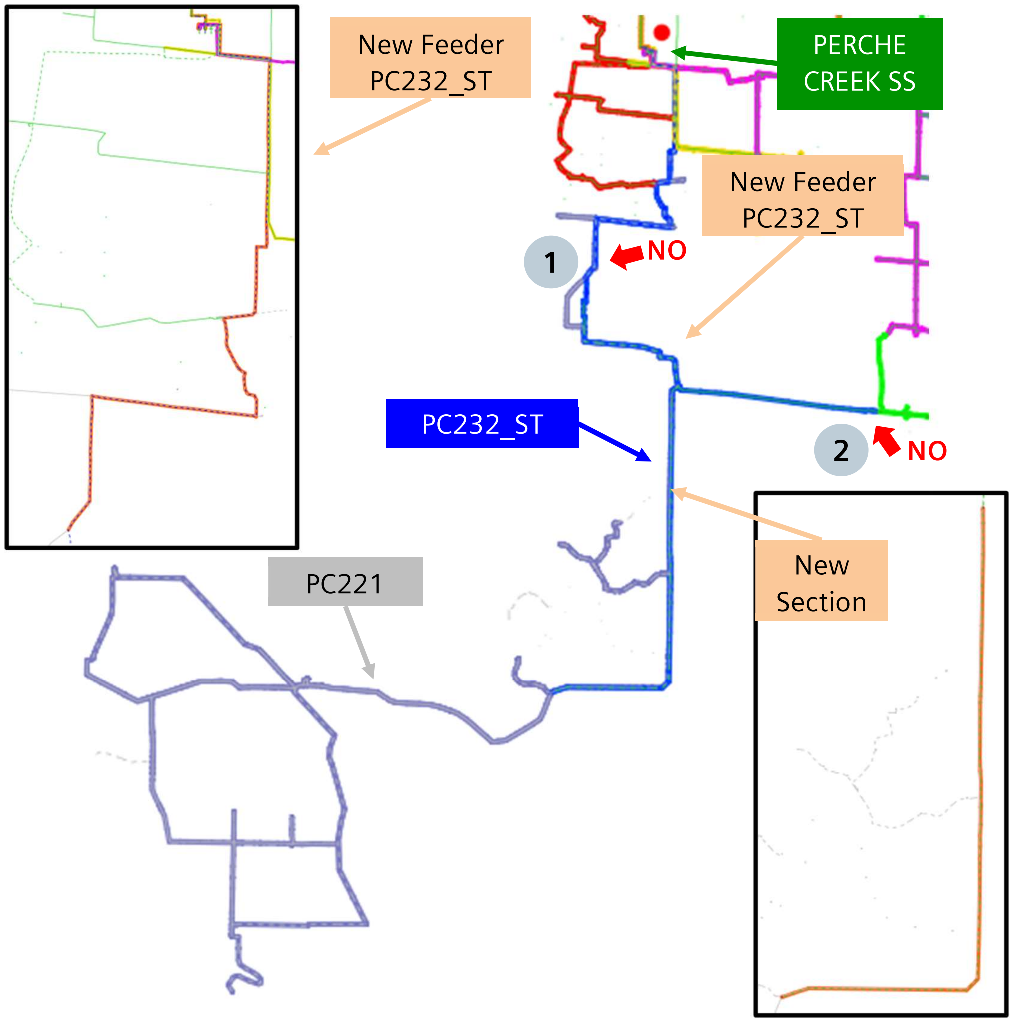


Figure 5-44 New configuration of Area 5 in conventional alternative

A Non-Wires Alternative was designed instead of the new section (Project 11 – Part2) whose role is only for providing backup for residential area. This solution consists of a combination of solar and battery energy storage system (PV+BESS).

For a proper sizing of PV and BESS, the load profile of the feeder (PC221) and the residential area was considered (see Figure 5-45). PV and BESS were designed to support up to 4 hours outage which is typical maximum outage duration in region.

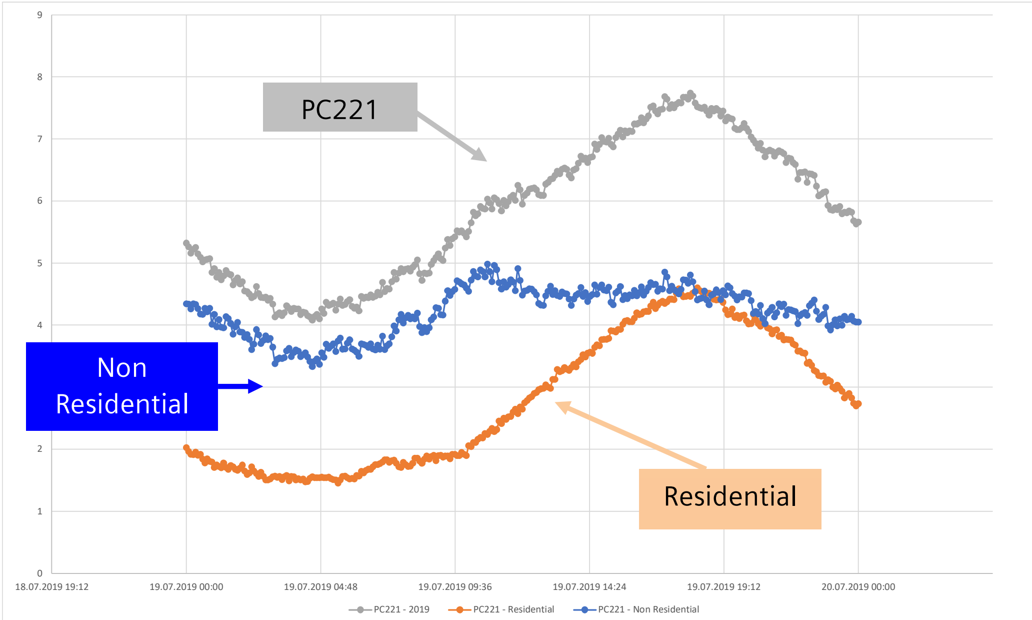


Figure 5-45 Load profile of PC221

Considering 2040 loads, an iterative analysis was carried out considering various sizes of PV to determine the potential energy requirements and power requirements of a BESS. The important point in this analysis is defining the 4-hour period when maximum energy not supplied occurs that needs to be supplied by the BESS.

For a 3.5 MW PV, the maximum not supplied energy occurs between 6 pm – 10 pm equal to approximately 16.0 MWh as shown in Table 5-29. This is an indicative value of BESS energy requirements. In the same period (6 pm – 10 pm), maximum peak load is 4.6 MW. This is indicative of power output requirements of the BESS.

As mentioned before, the analysis was conducted with different PV sizes. The result shows that even if PV size is increased, impact on battery size is very limited. Thus, increasing the PV beyond that necessary to charge the BESS is not required.

Based on the above, 3.5 MW PV and 4.60 MW – 4-hour battery was selected to supply residential loads in an emergency condition.

Table 5-29: Analyzing of maximum not supplied energy in 3.5 MW PV size in 2040

Start	End	Consumed Energy [MWh]	PV Support [MWh]	Not Supplied Energy [MWh]
0	4	7.21	0.00	7.21
1	5	6.39	0.00	6.39
2	6	6.21	0.29	5.92
3	7	6.25	1.41	4.84
4	8	6.49	3.40	3.09
5	9	6.80	5.92	0.88

Start	End	Consumed Energy [MWh]	PV Support [MWh]	Not Supplied Energy [MWh]
6	10	7.17	8.69	0.00
7	11	7.66	10.94	0.00
8	12	8.38	12.45	0.00
9	13	9.44	13.30	0.00
10	14	10.78	13.50	0.00
11	15	12.21	13.60	0.00
12	16	13.66	13.25	0.41
13	17	15.02	12.52	2.51
14	18	16.23	11.25	4.98
15	19	17.14	8.37	8.77
16	20	17.42	5.25	12.17
17	21	17.19	2.62	14.57
18	22	16.50	0.63	15.88
19	23	15.29	0.03	15.26
20	0	13.97	0.00	13.97
21	1	12.30	0.00	12.30
22	2	10.25	0.00	10.25
23	3	8.57	0.00	8.57

Table 5-30: Analyzing of different PV sizes in 2025

PV [MW]	Failure Start	Failure End	Min Battery Size [MWh]	PV Verification	Battery Output Power [MW]
0	16	20	15.72	Fail	4.15
1	17	21	14.76	Fail	4.15
2	18	22	14.53	Verified	4.15
3.5	18	22	14.26	Verified	4.15
4	18	22	14.17	Verified	4.15
5	18	22	14.00	Verified	4.15

Table 5-31: Analyzing of different PV sizes in 2040

PV [MW]	Failure Start	Failure End	Min Battery Size [MWh]	PV Verification	Battery Output Power [MW]
0	16	20	17.42	Fail	4.60
1	17	21	16.44	Fail	4.60
2	18	22	16.14	Verified	4.60
3.5	18	22	15.88	Verified	4.60
4	18	22	15.79	Verified	4.60
5	18	22	15.61	Verified	4.60

New capacitor banks are proposed to improve power factor at various locations. They are sized considering the preference to prevent injection of reactive power at the substation back to transmission. They are necessary for both alternatives and listed in Table 5-32 according to sizes. Additionally, location of capacitor banks is shown in Figure 5-46.

Table 5-32: New capacitor banks for Area 5

Feeder Name	2025 1200 kVAr
PC221	-
PC232_ST	2

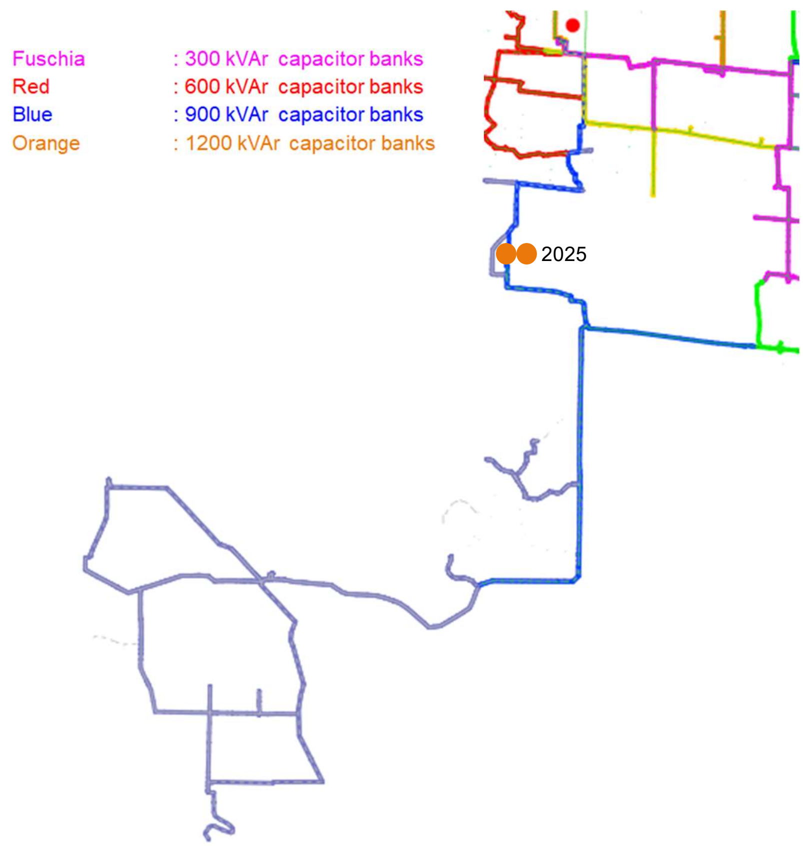


Figure 5-46 New capacitor banks in Area 5

The reinforced proposed system was analyzed under emergency conditions. Table 5-33 summarizes for feeders PC221 and PC232_ST what is the recommended backup feeder(s) for each term. These back up feeders can accept all load from main feeder (with the contingency) without loading or voltage violations.

Table 5-33: Back-up feeders of Area 5 for each term

Substation	Main Feeder	2025 Back-Up Feeder-1	2025 Back-Up Feeder-2	2030 Back-Up Feeder-1	2030 Back-Up Feeder-2	2040 Back-Up Feeder-1	2040 Back-Up Feeder-2
Perche Creek	PC221	PC232_ST	-	PC232_ST	-	PC232_ST	-
Perche Creek	PC232_ST	PC221	-	PC221	-	PC221	-

5.5.2.6 Area 6 – Perche Creek, Hinkson Creek and Harmony Branch Area

The Area 6 is shown in Figure 5-47 and includes the following feeders.

- From Perche Creek : PC212 and PC213
- From Hinkson Creek : HC213 and HC221
- From Harmony Branch: HB223 and HB232

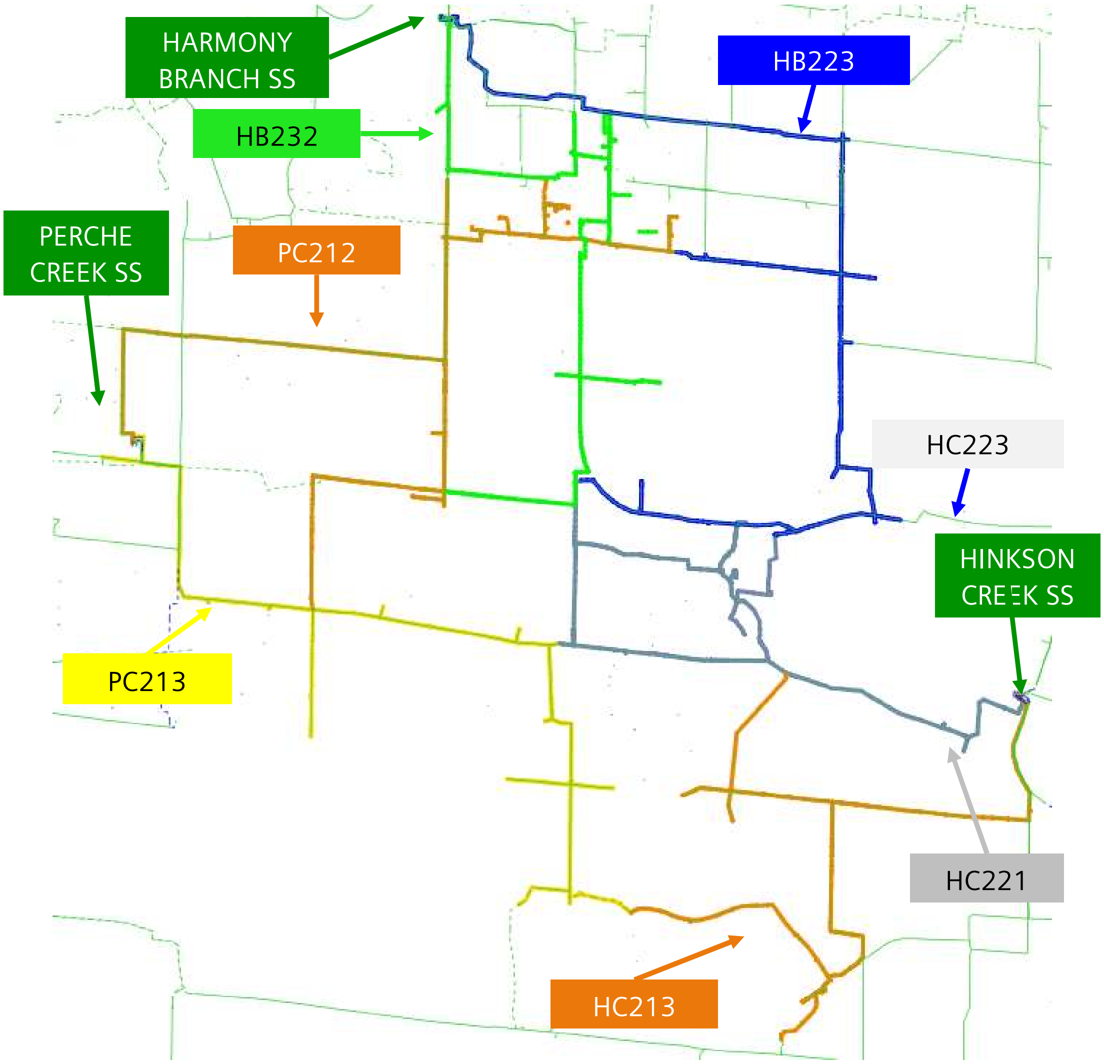


Figure 5-47 Supply area of associated feeders in Area 6

With the current configuration, the load at these feeders before any transfer is shown in Table 5-34.

Table 5-34: Feeder loads of Area 6 before any transfer or investment

Feeder	2020 P [MW]	2025 P [MW]	2030 P [MW]	2040 P [MW]
HC221	6.45	6.35	6.45	6.88
HB223	6.08	5.98	6.08	6.45
PC212	5.71	5.62	5.50	5.53

HB232	6.40	6.30	6.17	6.25
PC213	7.49	7.38	7.16	7.35
HC213	5.99	5.89	5.70	5.80

PC212, PC213, HC213, HC221, HB223 and HB232 are adjacent feeders to each other. Each feeder is connected to other adjacent feeder mostly at the feeder end. Although they have good connections to transfer load during emergency, feeders do not have enough capacity to supply all transferred load without overloading or some voltage drop issues.

PC212 supply area has connections with HB223. When PC212 is transferred to HB223, there would be overloading in HB223 substation exit and along the feeder of 103.0% in 2025 as shown in Table 5-35 and Figure 5-48.

Table 5-35: Violations under PC212 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Perche Creek	PC212	HB223	-	103.0%	99.4%	2025

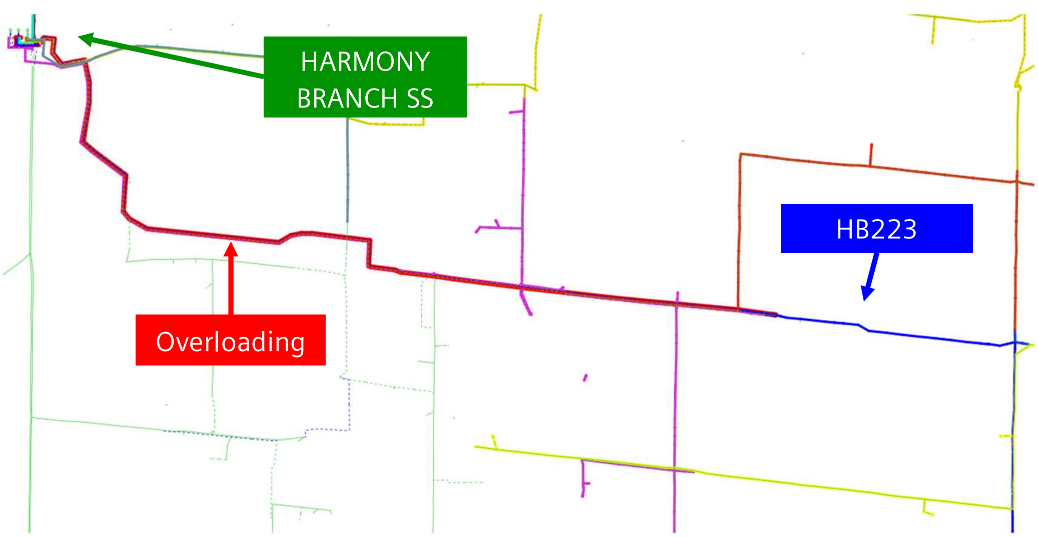


Figure 5-48 Overloading violation under PC212 emergency condition in 2025

Although HC213 and HC221 feeders are adjacent feeders to PC213, they cannot provide a full back up for PC213. When PC213 is transferred to HC221, there would be overloading violations at HC221 substation exit of 122.4% and slight voltage violation at the end of the feeder as 98.9% and shown in Table 5-36, Figure 5-49 and Figure 5-50 in 2025.

Table 5-36: Violations under PC213 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Perche Creek	PC213	HC221	-	122.4%	98.9%	2025

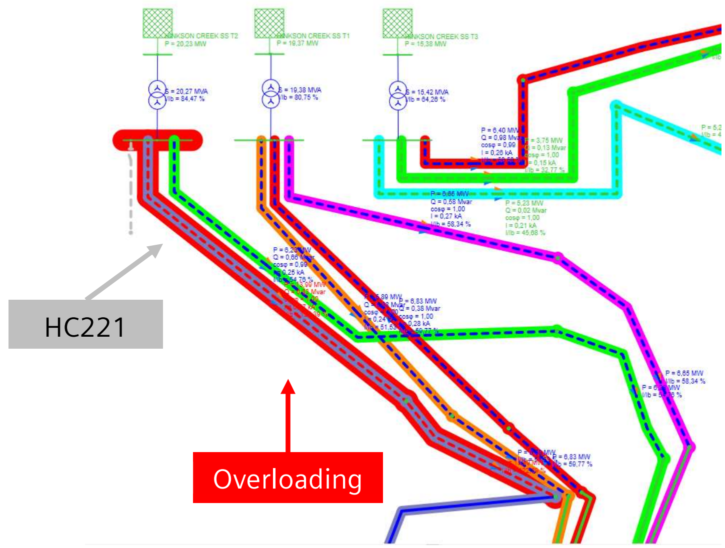


Figure 5-49 Overloading violation under PC213 emergency condition in 2025

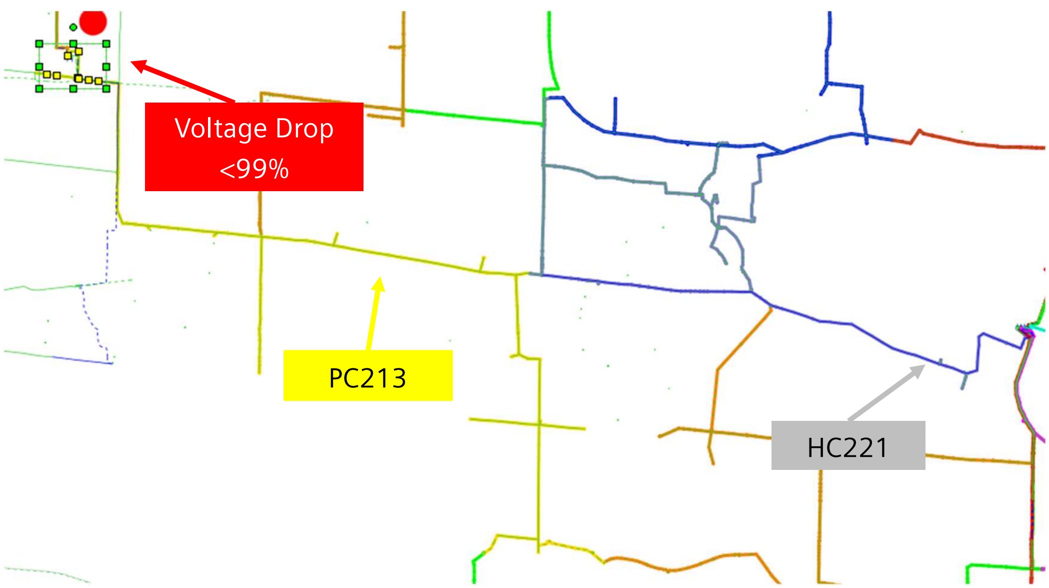


Figure 5-50 Voltage violation under PC213 emergency condition in 2025

Although HB223 and PC213 feeders are adjacent feeders to HC221, they cannot provide a full back up for HC221. When HC221 is transferred to PC213, PC213 substation exit would be overloaded to 122% and Perche Creek T1 to 113% as well in 2025. Once HC221 is transferred to HB223, there would be overloading violation at substation exit and along the feeder to 111.2%. Additionally, there would be voltage violation at the end of feeders as 97.9%. These violations are shown in Table 5-37, Figure 5-51 and Figure 5-52.

Table 5-37: Violations under HC221 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Hinkson Creek	HC221	HB223	-	111.2%	97.9%	2025

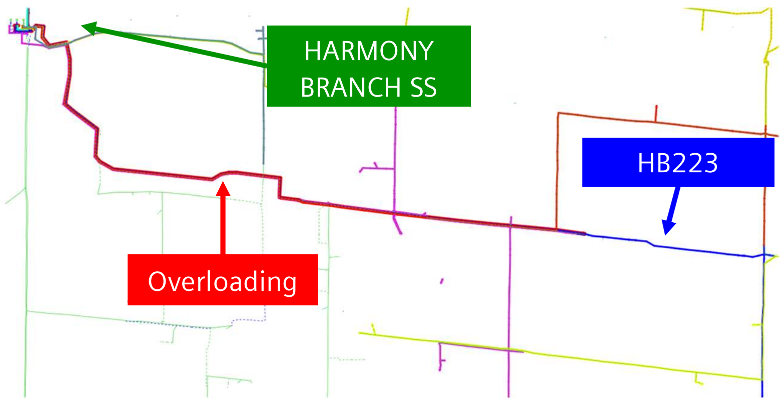


Figure 5-51 Overloading violation under HC221 emergency condition in 2025

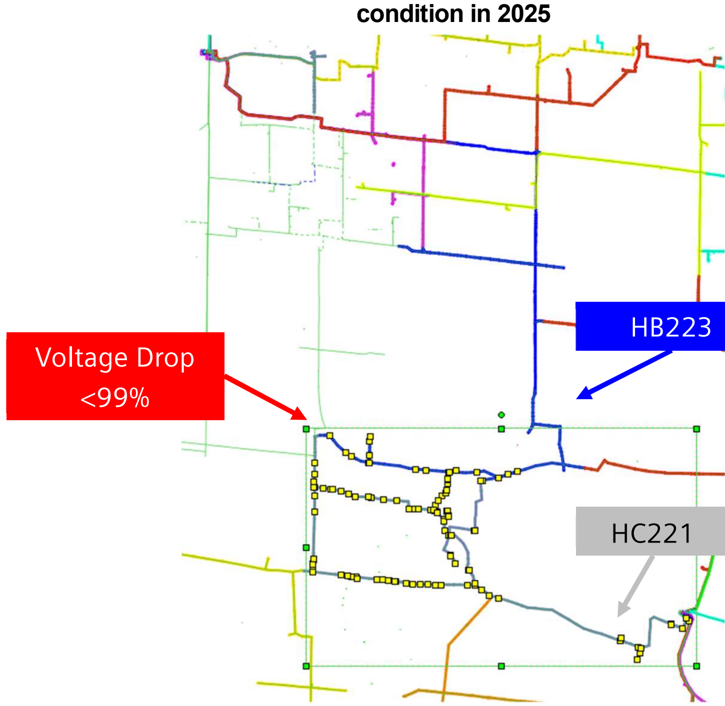


Figure 5-52 Voltage violation under HC221 emergency condition in 2025

Although HC221 and HC233 feeders are adjacent feeders to HB223, they cannot provide a full back up for HB233. HC221 would be a better option to provide backup considering lower load than HC233. However, there would be an overloading violation as 109.3% at substation exit in 2025 when HB223 is transferred to HC221. These violations are shown in Table 5-38 and Figure 5-53.

Table 5-38: Violations under HB223 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Harmony Branch	HB223	HC221	-	109.3%	99.5%	2025

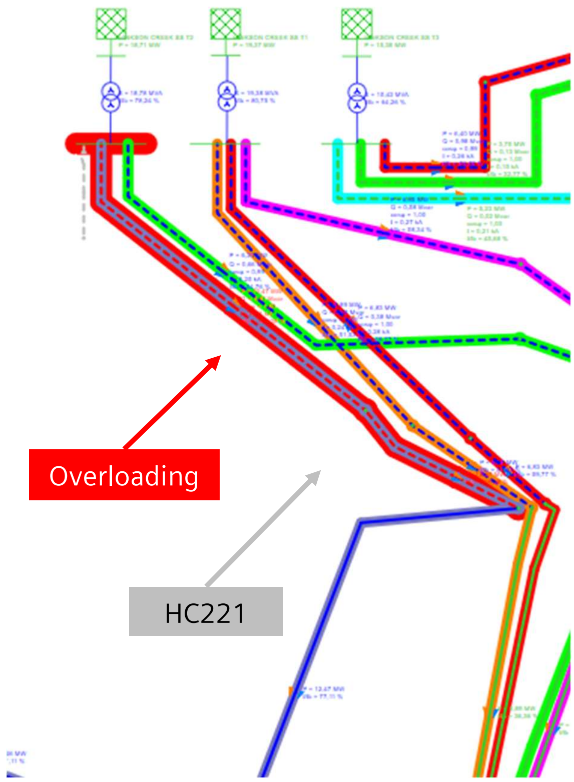


Figure 5-53 Overloading violation under HB223 emergency condition in 2025

HC221 and PC212 feeders are adjacent feeders to HB232, they cannot provide a full back up for HB232. When HB232 is transferred to HC221, there would be overloading violation of 113.2% at substation exit and voltage violation along the feeder to 98.1% in 2025. These violations are shown in Table 5-39, Figure 5-54 and Figure 5-55. In the other option PC212 backup condition, Perche Creek T1 would be overloaded in addition to possible voltage and overloading violations in 2025.

Table 5-39: Violations under HB232 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year

Harmony Branch	HB232	HC221	-	113.2%	98.1%	2025

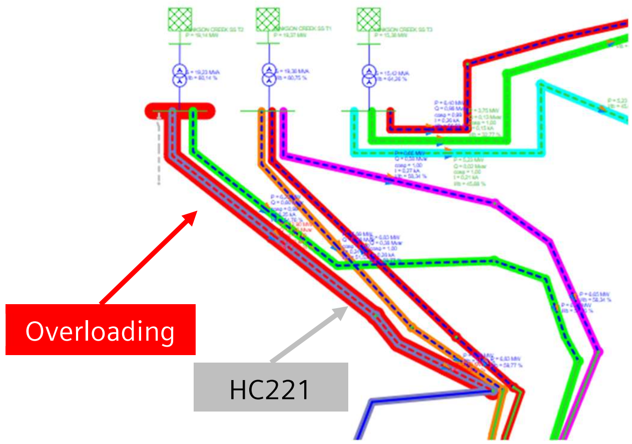


Figure 5-54 Overloading violation under HB232 emergency condition in 2025

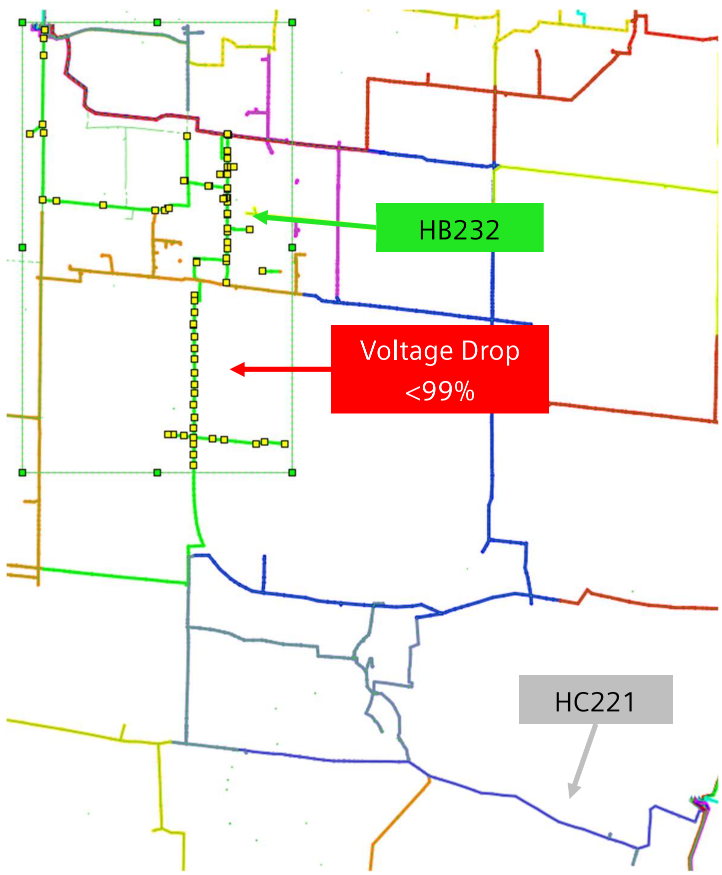


Figure 5-55 Voltage violation under HB232 emergency condition in 2025

HC221 and PC213 feeders are adjacent feeders to HC213, they cannot provide a full back up for HC213. HC221 is the better option considering lower load than PC213. However, substation exit would be overloaded to 108.2% in 2025 once

HC213 is transferred to HC221. In the second PC213 option, there would be voltage violation to 98.2% at the feeder end and overloading violation at substation exit as 118.5% and Perche Creek T1 loading of 111% as well in 2025. The violations in HC221 options are shown below

Table 5-40: Violations under HC213 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Hinkson Creek	HC213	HC221	-	108.2%	100.4%	2025

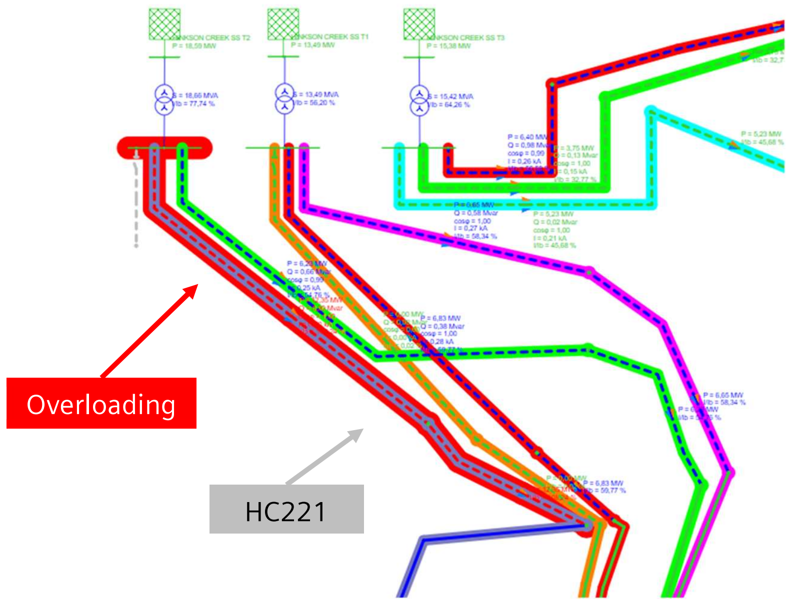


Figure 5-56 Overloading violation under HC213 emergency condition in 2025

To address these multiple issues, a new feeder PC231_ST (Project 8, 500 kcmil CU – 0.079 mi) is proposed to de-load and create back up capacity on the feeders above. The new feeder is to be connected to the new transformer at Perche Creek Substation and connect to the first switch at PC223 (see figure below). There is a section of feeder between the switch above and PC212 which is a good route to create a supply area for new feeder (PC231_ST) and connection with other related feeders.

PC231_ST final supply area was determined considering emergency switching between the feeders. PC231_ST would take some load from PC212, PC213, HB232 and HC221. When feeder supply areas are reconfigured with PC231_ST, all feeders in this area can be transferred to adjacent feeders without any overloading or voltage violations.

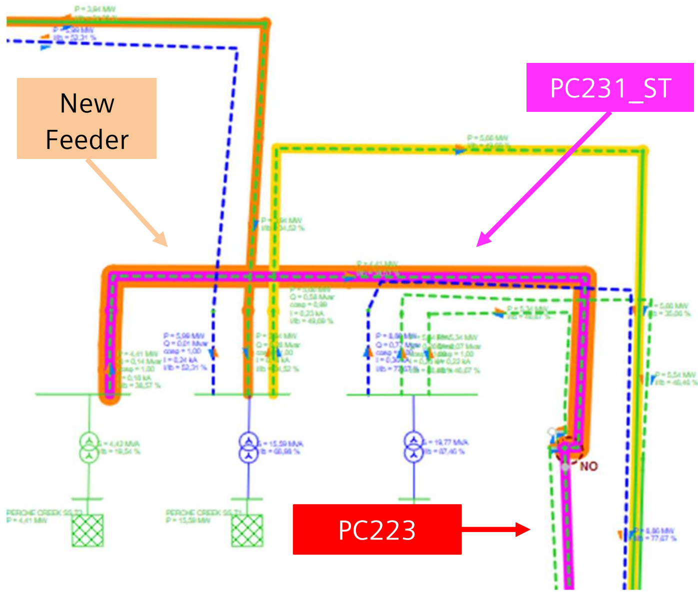


Figure 5-57 Project 8 - New feeder PC231_ST

Reconfiguration of supply areas and related switching for Area 6 is illustrated in Figure 5-58. The new loads for the associated feeders are shown in Table 5-41.

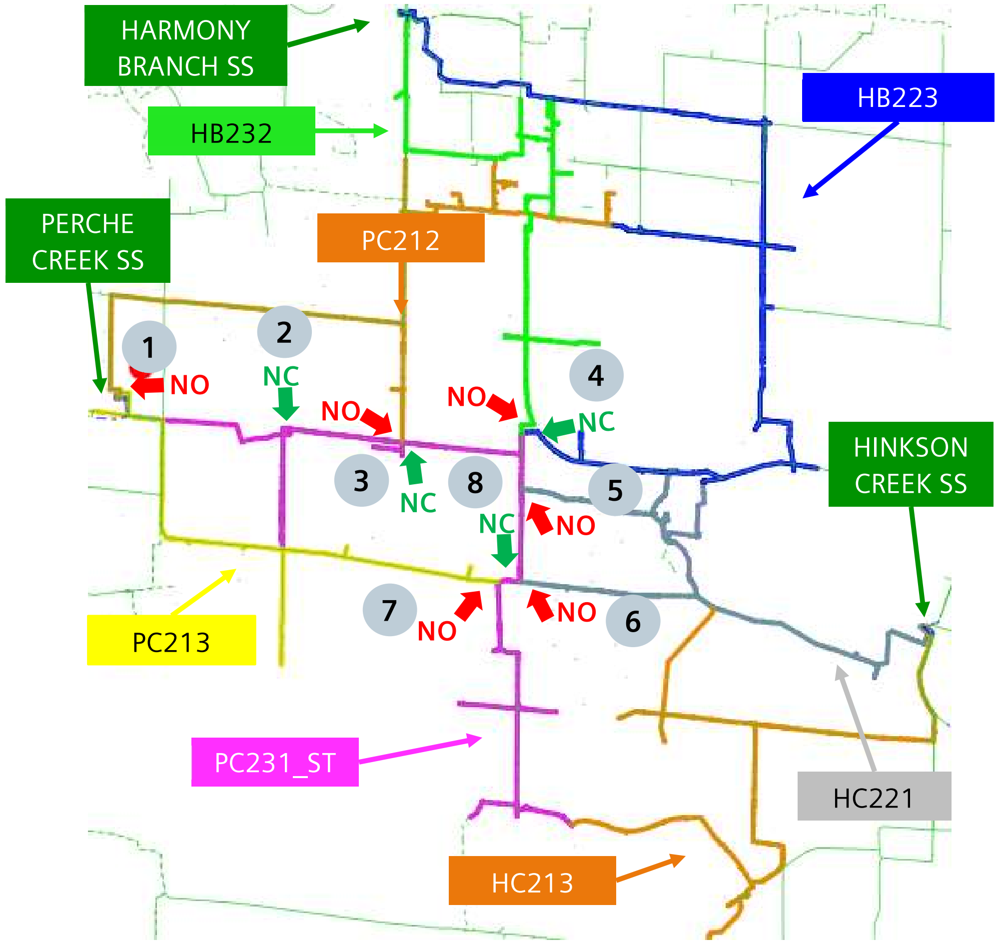


Figure 5-58 Proposed supply area for Area 6 in 2025

Table 5-41: Feeder loads of Area 6 after supply area reconfiguration

Feeder	2025 P [MW]	2030 P [MW]	2040 P [MW]
HC221	5.61	5.71	6.12
HB223	5.98	6.08	6.45
PC212	3.94	3.89	3.95
HB232	5.96	5.84	5.92
PC213	5.66	5.46	5.44
HC213	5.89	5.70	5.80
PC231_ST	4.41	4.32	4.51

New capacitor banks are proposed to improve power factor at various locations. They are sized considering the preference to prevent injection of reactive power at the substation back to transmission. They are listed in Table 5-42 according to sizes and all are proposed for 2025. Additionally, location of capacitor banks is shown in Figure 5-59.

Table 5-42: New capacitor banks for Area 6

Feeder Name	2025 300 kVAr	2025 600 kVAr
HC221	-	-
HB223	-	-
PC212	-	-
HB232	-	1
PC213	1	-
HC213	1	-
PC231_ST	-	-

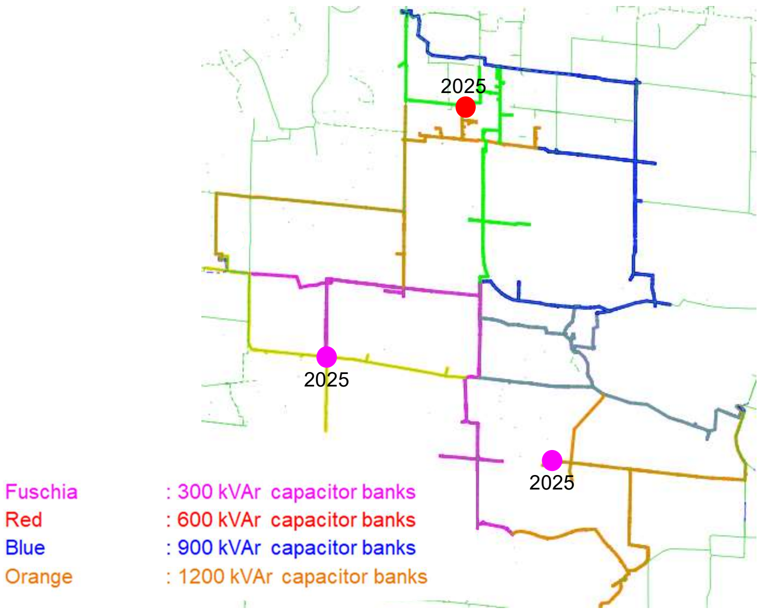


Figure 5-59 New capacitor banks in Area 6

The reinforced proposed system was analyzed under emergency conditions. Table 5-43 summarizes for feeders HB223, HB232, HC213, HC221, PC212, PC213 and PC231_ST what is the recommended backup feeder(s) for each term. These back up feeders can accept all load from main feeder (with the contingency) without loading or voltage violations.

Table 5-43: Back-up feeders of Area 6 for each term

Substation	Main Feeder	2025 Back-Up Feeder-1	2025 Back-Up Feeder-2	2030 Back-Up Feeder-1	2030 Back-Up Feeder-2	2040 Back-Up Feeder-1	2040 Back-Up Feeder-2
Harmony Branch	HB223	PC231_ST	-	PC231_ST	-	PC231_ST	-
Harmony Branch	HB232	PC231_ST	-	PC231_ST	-	PC231_ST	-
Hinkson Creek	HC213	PC231_ST	-	PC231_ST	-	PC231_ST	-
Hinkson Creek	HC221	PC231_ST	-	PC231_ST	-	PC231_ST	-
Perche Creek	PC212	HB223	-	HB223	-	HB223	-
Perche Creek	PC213	PC231_ST	-	PC231_ST	-	PC231_ST	-

5.5.2.7 Area 7 – Power Plant, Hinkson Creek and Harmony Branch Area

The Area 7 is shown in Figure 5-60 and includes the following feeders.

- From Power Plant: PP213
- From Hinkson Creek: HC233
- From Harmony Branch: HB231

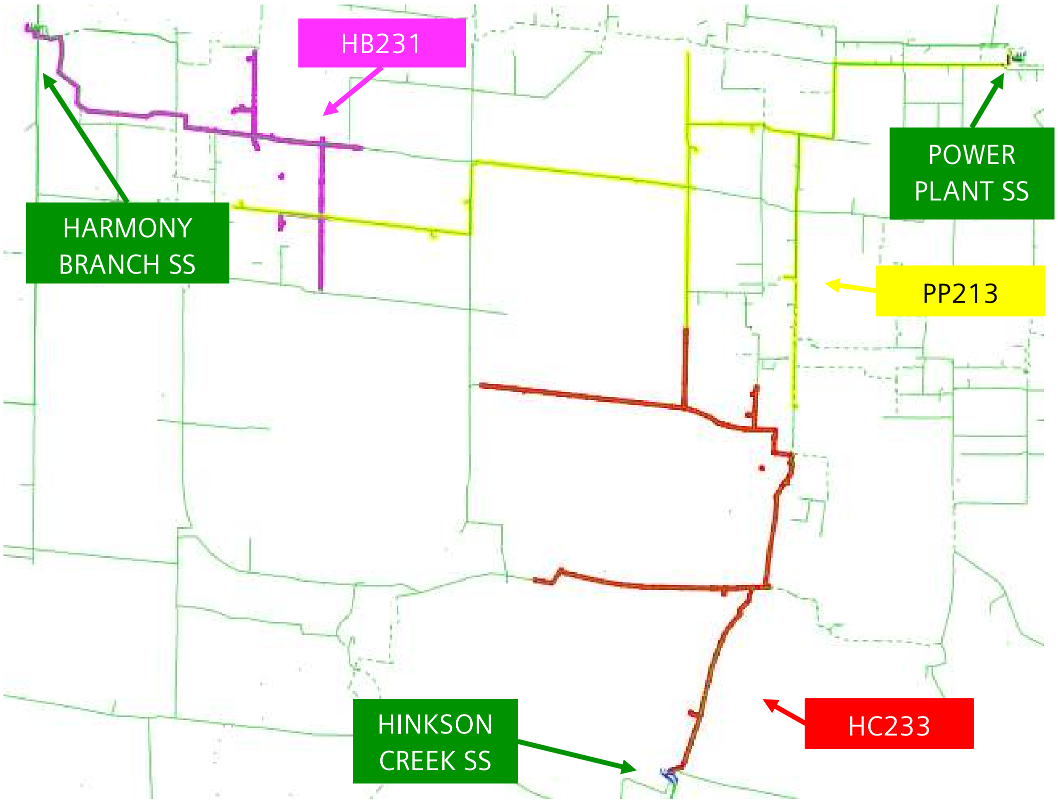


Figure 5-60 Supply area of associated feeders in Area 7

With the current configuration, the load at these feeders before any transfer is shown in Table 5-44.

Table 5-44: Feeder loads of Area 7 before any transfer or investment

Feeder	2020 P [MW]	2025 P [MW]	2030 P [MW]	2040 P [MW]
PP213	7.62	7.50	7.26	7.17
HC233	6.51	6.40	7.00	8.16
HB231	3.85	3.79	3.68	3.68

Although HB223, PP214 and HC233 are adjacent feeders to PP213, none of them has enough capacity to receive PP213 load. In each option, overloading would be an important issue and voltage violation might appear in some cases. For example, there would be an overloading at substation exit and along the feeder of 119.0% when PP213 is transferred to HB223 in 2025. These violations are shown in Table 5-45 and Figure 5-61.

Table 5-45: Violations under PP213 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Power Plant	PP213	HB223	-	119.0%	100.2%	2025

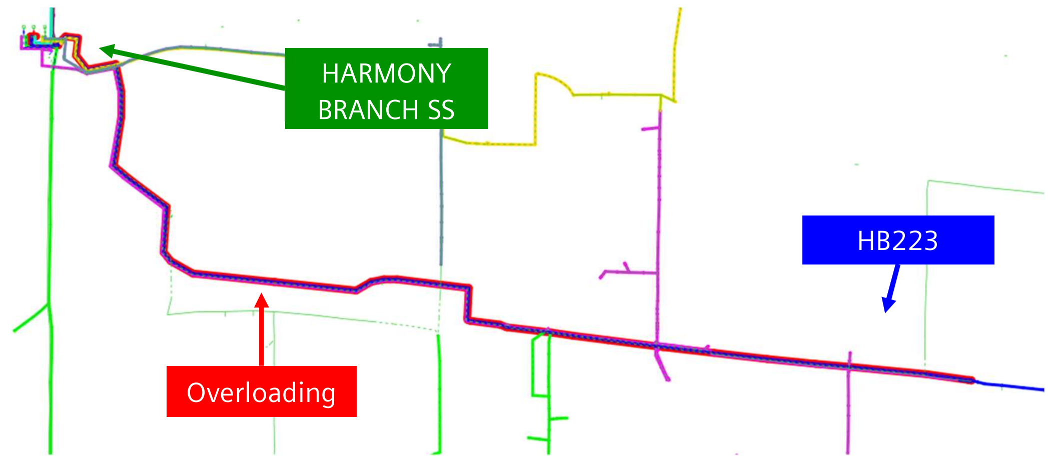


Figure 5-61 Overloading violation under PP213 emergency condition in 2025

PP213 and HB231 feeder ends are close to each other. Therefore, very short section between these feeders (Project 9, 500 kcmil CU – 0.002 mi) is proposed. After this section is built, PP213 could be transferred to HB231 in each term without any violation. Additionally, some of the load of PP213 is proposed to be transferred to HB231 to prevent overloading of Power Plant T1 in case of transferring load from HC233 to PP214.

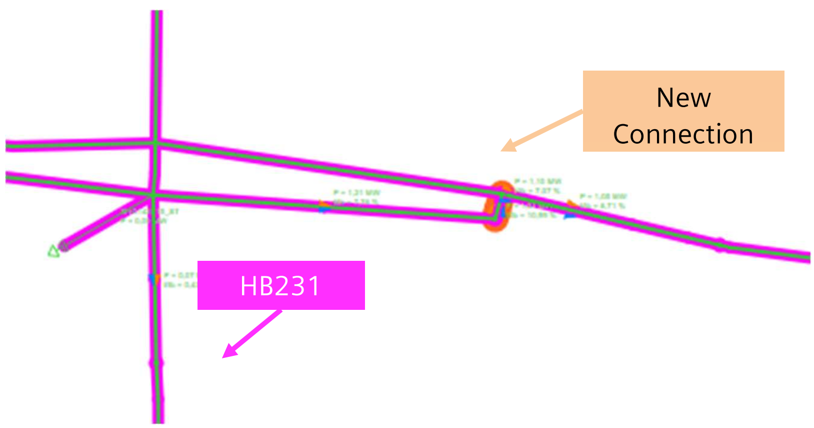


Figure 5-62 Project 9 - New section between PP213 and HB231

With existing configuration, HB231 can be transferred to HB223 in each term without any violation. However, once the new connection is built between PC213 and HB231 and the supply area of each feeder is reconfigured, PC213 would be the preferred backup feeder for HB231 in each term.

HB223, PP213 and PP214 feeders are adjacent feeders to HC233, none of them has enough capacity to provide back up for HC233. PP214 has the lowest load within the mentioned feeders, but it could not provide a full backup for HC233. In addition to PP214, PP213 could supply part of HC233. However, Power Plant T1 would be overloaded in 2025 as PP213 and PP214 connected to same transformer. As mentioned before, some of the loads at PP213 are proposed to be transferred to HB231 to create room in Power Plant T1 for emergency conditions in 2025.

After de-loading Power Plant T1, HC233 feeder can be transferred to PP214 and HB223 without any overloading or voltage violation in 2025 and 2030. However, when HC233 is partially transferred to PP214, the substation exit is overloaded to 102.6% and there would be voltage violation along the feeder as shown in Table 5-46, Figure 5-63 and Figure 5-64. The main reason of these issues is that capacitor banks connected to HC233 would be connected to HB223 in emergency and there would no reactive power support to PP214. To address this issue, 1.5 MVAr capacitor (Project 10, 1.5 MVAr capacitor bank) is proposed at the normally open point between PP214 and HC233. In normal operation, this capacitor bank should be operated open and in emergency condition the capacitor bank should be in service.

Table 5-46: Violations under HC233 emergency condition in 2040

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Hinkson Creek	HC233	PP214	HB223	102.6%	98.5%	2040

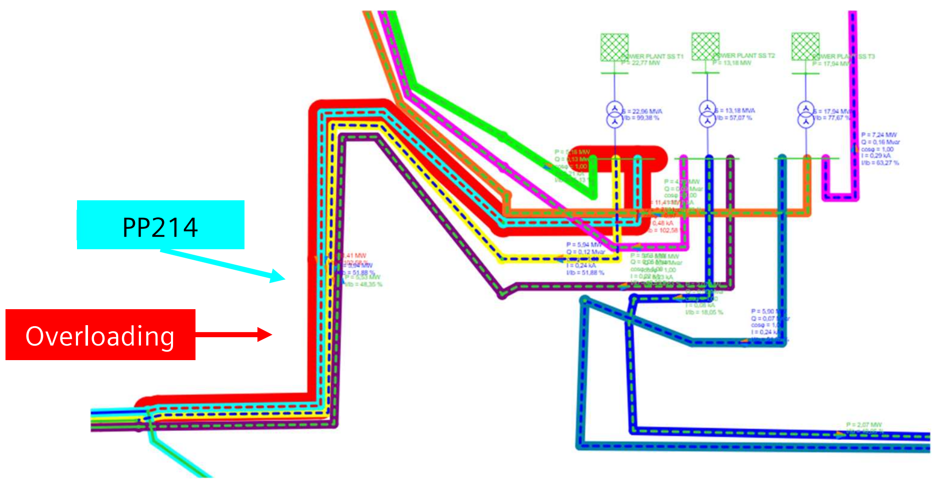


Figure 5-63 Overloading violation under HC233 emergency condition in 2040

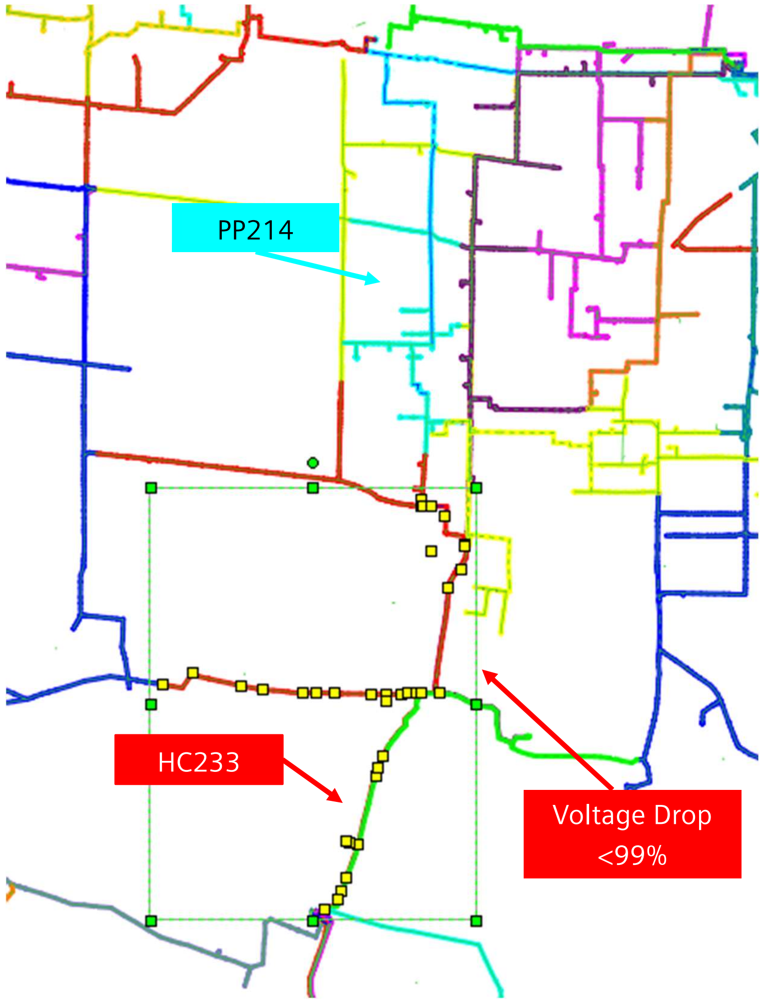


Figure 5-64 Voltage violation under HC233 emergency condition in 2040

Reconfiguration of supply areas and related switching for Area 7 is illustrated in Figure 5-65. The new loads for the associated feeders are shown in Table 5-47.

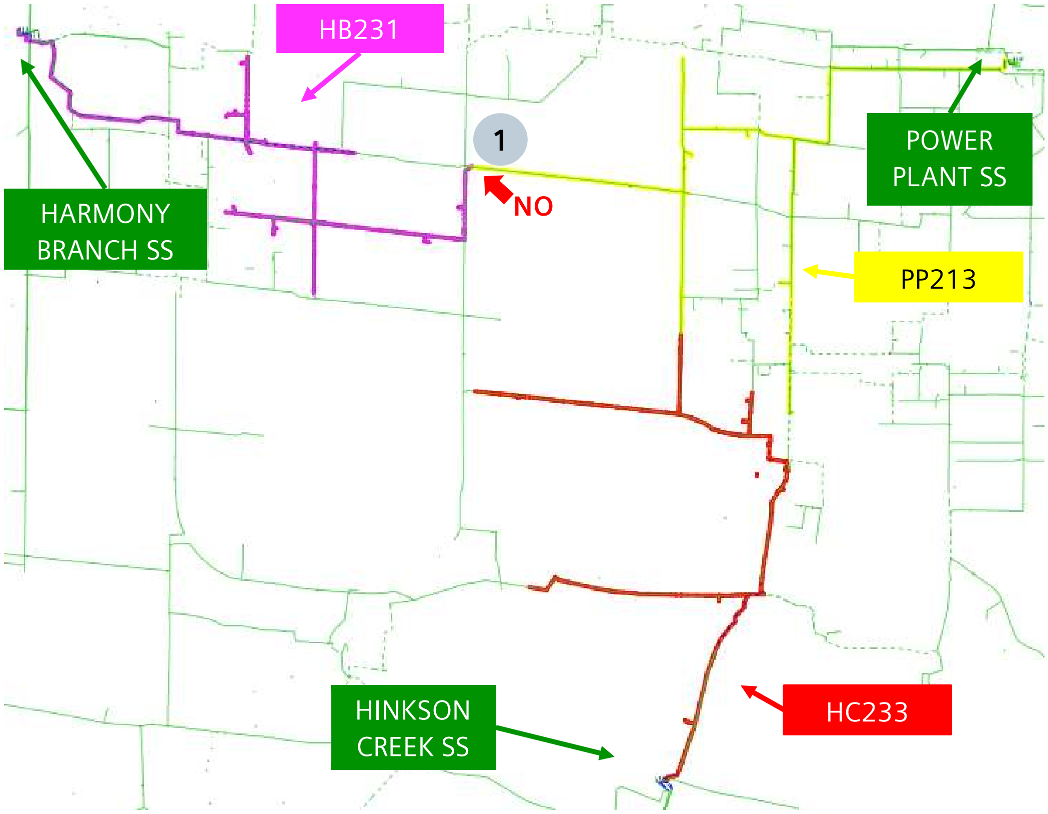


Figure 5-65 Proposed supply area for Area 7 in 2025

Table 5-47: Feeder loads of Area 7 after supply area reconfiguration

Feeder	2025 P [MW]	2030 P [MW]	2040 P [MW]
PP213	6.26	6.04	5.94
HC233	6.40	7.00	8.17
HB231	5.00	4.87	4.88

New capacitor banks are proposed to improve power factor at various locations. They are sized considering the preference to prevent injection of reactive power at the substation back to transmission. They are listed (including Project 10) in Table 5-48 according to sizes and in service dates. Additionally, location of capacitor banks is shown in Figure 5-66.

Table 5-48: New capacitor banks for Area 7

Feeder Name	2025 900 kVAr	2040 300 kVAr	1200 kVAr
PP213	-	-	-
HC233	-	1	1
HB231	1	-	-

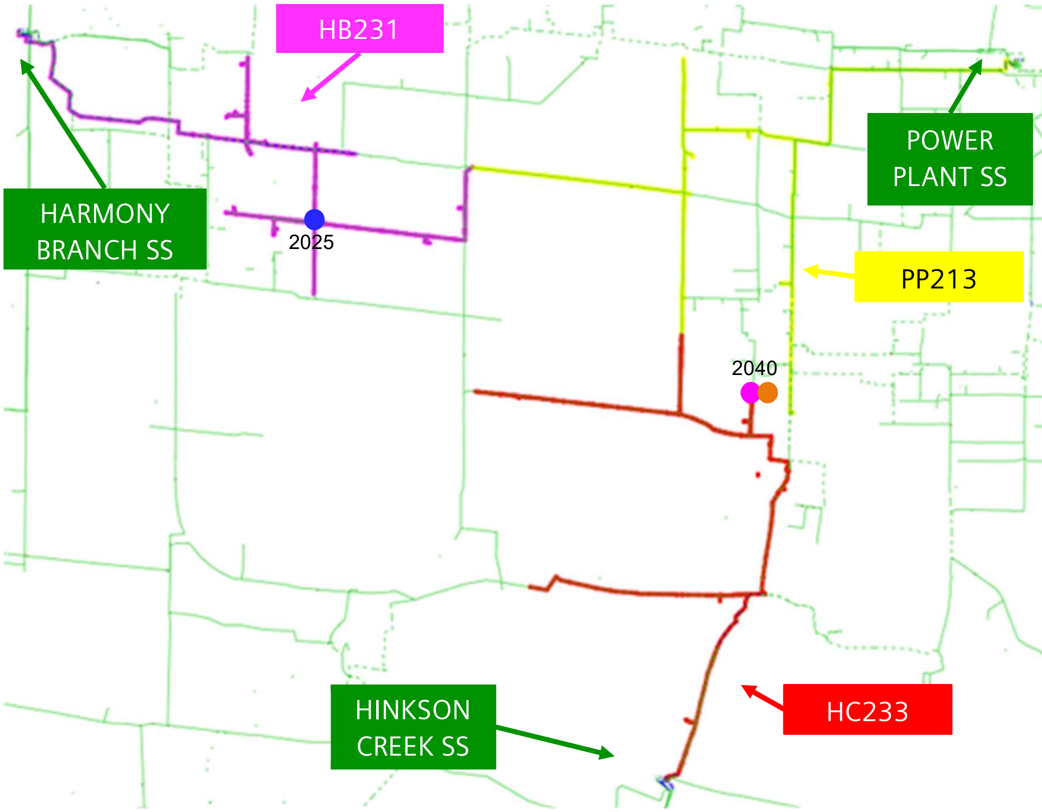


Figure 5-66 New capacitor banks in Area 7

The reinforced proposed system was analyzed under emergency conditions. Table 5-49 summarizes for feeders HB231, HC233 and PP213 what is the recommended backup feeder(s) for each term. These back up feeders can accept all load from main feeder (with the contingency) without loading or voltage violations.

Table 5-49: Back-up feeders of Area 7 for each term

Substation	Main Feeder	2025 Back-Up Feeder-1	2025 Back-Up Feeder-2	2030 Back-Up Feeder-1	2030 Back-Up Feeder-2	2040 Back-Up Feeder-1	2040 Back-Up Feeder-2
Harmony Branch	HB231	PP213	-	PP213	-	PP213	-
Hinkson Creek	HC233	PP214	HB223	PP214	HB223	PP214	HB223
Power Plant	PP213	HB231	-	HB231	-	HB231	-

5.5.2.8 Area 8 – Harmony Branch and Perche Creek Area

The Area 8 is shown in Figure 5-67 and includes the following feeders:

- From Harmony Branch: HB212, HB221 and HB233
- From Perche Creek: PC211, PC222 and PC223

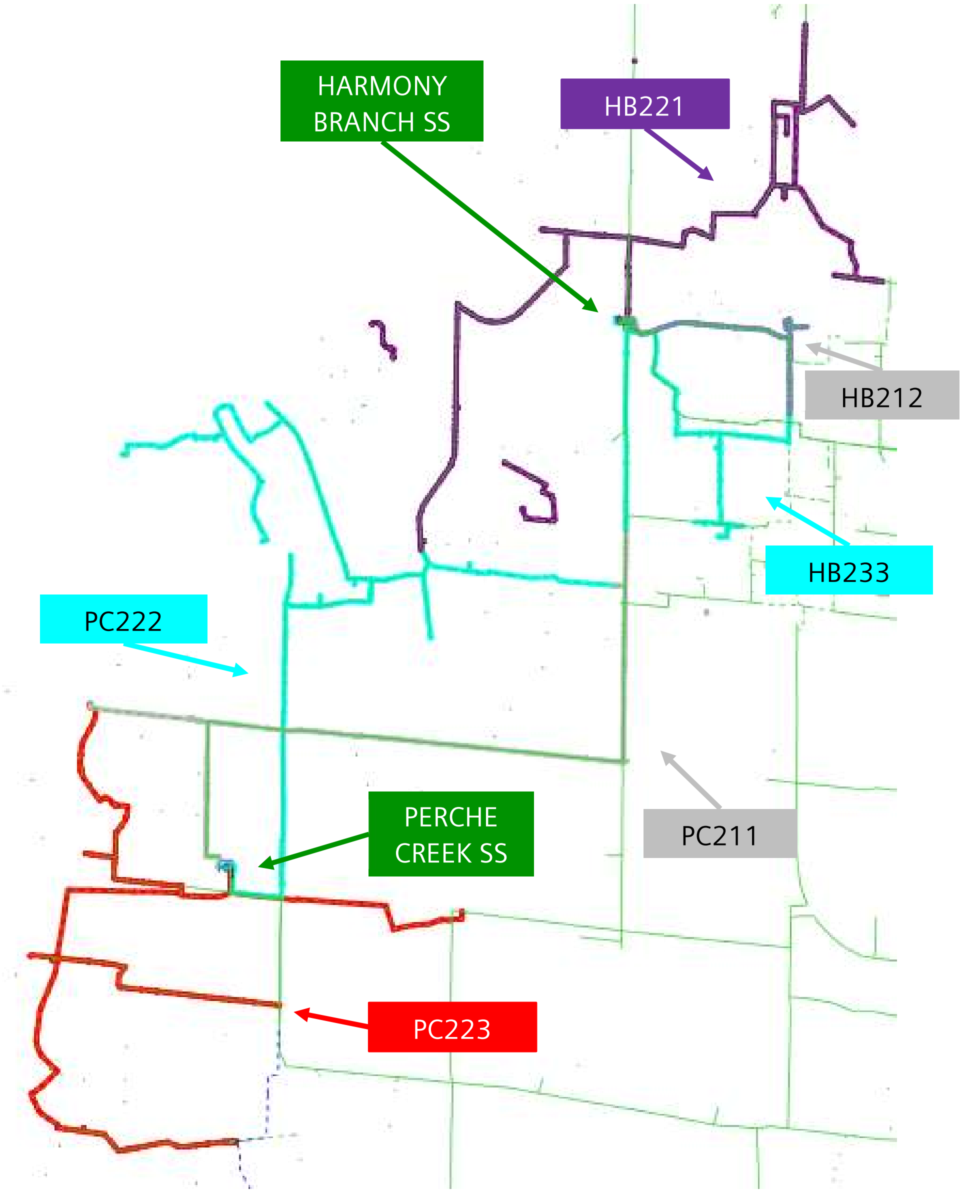


Figure 5-67 Supply area of associated feeders in Area 8

With the current configuration, the load at these feeders before any transfer is shown in Table 5-50.

Table 5-50: Feeder loads of Area 8 before any transfer or investment

Feeder	2020 P [MW]	2025 P [MW]	2030 P [MW]	2040 P [MW]
HB212	3.43	3.37	3.38	3.53
HB221	5.32	5.52	5.59	6.07
HB233	5.84	5.75	5.72	5.87
PC211	6.01	5.99	5.82	5.87
PC222	5.51	5.54	5.50	5.86
PC223	5.32	5.34	5.22	5.54

HB233 and HB232 feeders are adjacent feeders. When HB233 is transferred to HB232, the substation exit would be overloaded to 103% in 2025. Therefore, supply area of HB233 is reconfigured and the end sections of the feeder are transferred to HB212. By reducing the load supplied from HB233, it could be transferred to HB232 without any loading or voltage violation in each term.

After reconfiguration of HB212 supply area, when HB212 is transferred to HB233, there would be an overloading violation as 194.7% in a very short section since it has lower conductor size (4/0) as shown in Table 5-51 and Figure 5-68. Thus, this short section should be upgraded to 500 kcmil CU (Project 12, 500 kcmil CU – 0.005 mi). After this reinforcement is in place, HB212 can be transferred to HB233 without any voltage or loading violation in each term.

Table 5-51: Violations under HB212 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Harmony Branch	HB212	HB233	-	194.7%	102.3%	2025

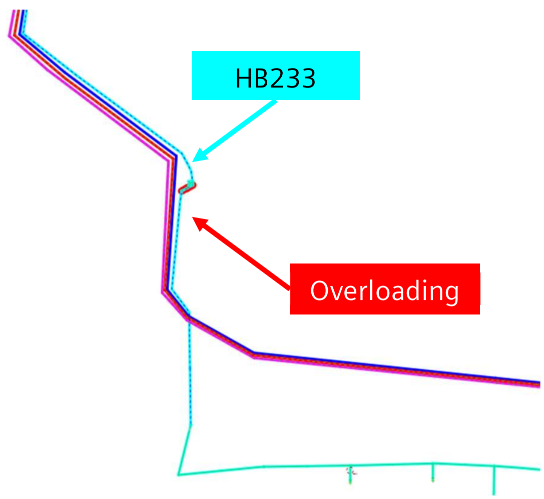


Figure 5-68 Overloading violation under HB212 emergency condition in 2025

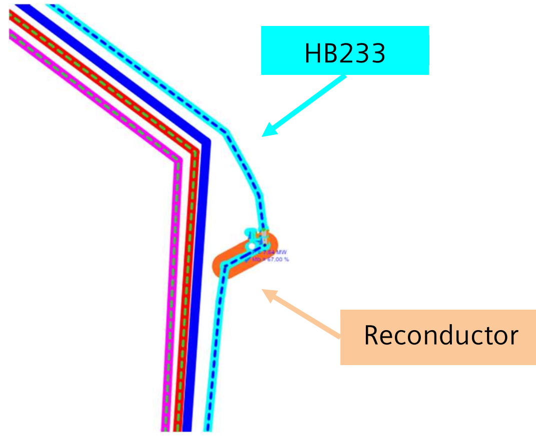


Figure 5-69 Project 12 - Reconductoring a short section in HB233

HB221 and HB213 are adjacent feeders and HB221 can be transferred to HB213 without any loading or voltage violation in each term.

PC211 and HB232 are adjacent feeders. However, there would be an overloading violation at feeder head in 2025 when PC211 is transferred to HB232. In order to address this issue, PC211 supply area is reconfigured and sections of PC211 are transferred to PC223. After this supply area reconfiguration, PC211 can be transferred to HB232 without any loading or voltage violation in each term.

PC223 has a connection with PC211 on the north side and with PC221 in the south. When PC223 is partially transferred to PC221, there would be slight voltage violation at the water treatment facility in 2025. Therefore, PC223, PC221 and PC232_ST (Project 11 - Part 1) supply area reconfigured, and load transferred from PC221 to PC232_ST. After this reconfiguration, PC223 can be transferred to PC232_ST and PC211 without any loading or voltage violation in each term.

PC222 and PC211 are adjacent feeders and PC222 can be transferred to PC211 without any loading or voltage violation in each term.

Reconfiguration of supply areas and related switching for Area 8 is illustrated in Figure 5-70. The new loads for the associated feeders are shown in Table 5-52.

Table 5-52: Feeder loads of Area 8 after supply area reconfiguration

Feeder	2025 P [MW]	2030 P [MW]	2040 P [MW]
HB212	4.43	4.43	4.60
HB221	5.52	5.59	6.07
HB233	4.68	4.67	4.80
PC211	4.94	4.76	4.76
PC222	5.54	5.50	5.86
PC223	6.40	6.28	6.65

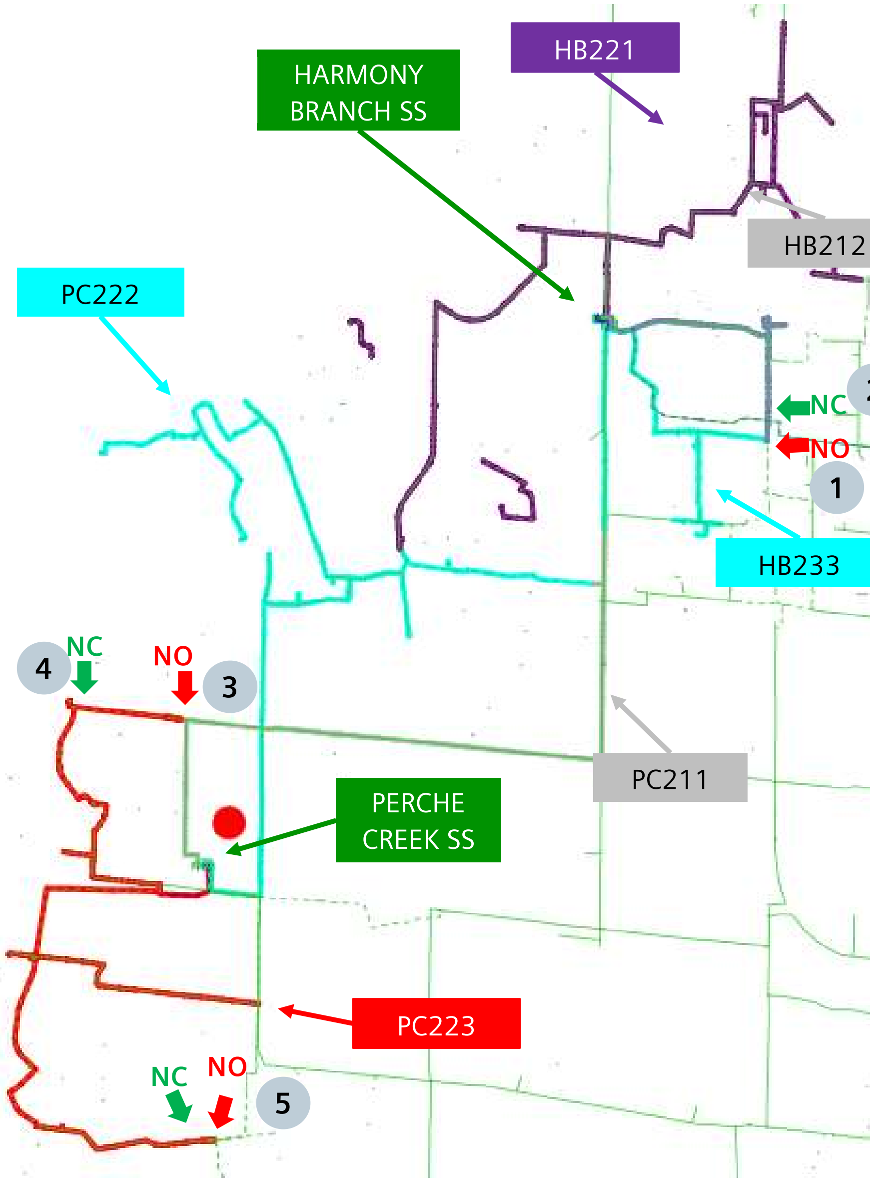


Figure 5-70 Proposed supply area for Area 8 in 2025

Reactive power consumptions and power factors of associated feeders were evaluated and no need for additional capacitor banks for this area was identified.

The reinforced proposed system was analyzed under emergency conditions. Table 5-53 summarizes for feeders HB212, HB221, HB233, PC211, PC222 and PC223 what is the recommended backup feeder(s) for each term. These back up feeders can accept all load from main feeder (with the contingency) without loading or voltage violations.

Table 5-53: Back-up feeders of Area 8 for each term

Substation	Main Feeder	2025 Back-Up Feeder-1	2025 Back-Up Feeder-2	2030 Back-Up Feeder-1	2030 Back-Up Feeder-2	2040 Back-Up Feeder-1	2040 Back-Up Feeder-2
Harmony Branch	HB212	HB233	-	HB233	-	HB233	-
Harmony Branch	HB221	HB213	-	HB213	-	HB213	-
Harmony Branch	HB233	HB232	-	HB232	-	HB232	-
Perche Creek	PC211	HB232	-	HB232	-	HB232	-
Perche Creek	PC222	PC211	-	PC211	-	PC211	-
Perche Creek	PC223	PC232_ST	PC211	PC232_ST	PC211	PC232_ST	PC211

5.5.2.9 Area 9 – Grindstone and Hinkson Creek Area

The Area 9 is shown in Figure 5-71 and includes the following feeders:

- From Grindstone: GS211, GS231 and GS233
- From Hinkson Creek: HC211, HC212, HC223 and HC231

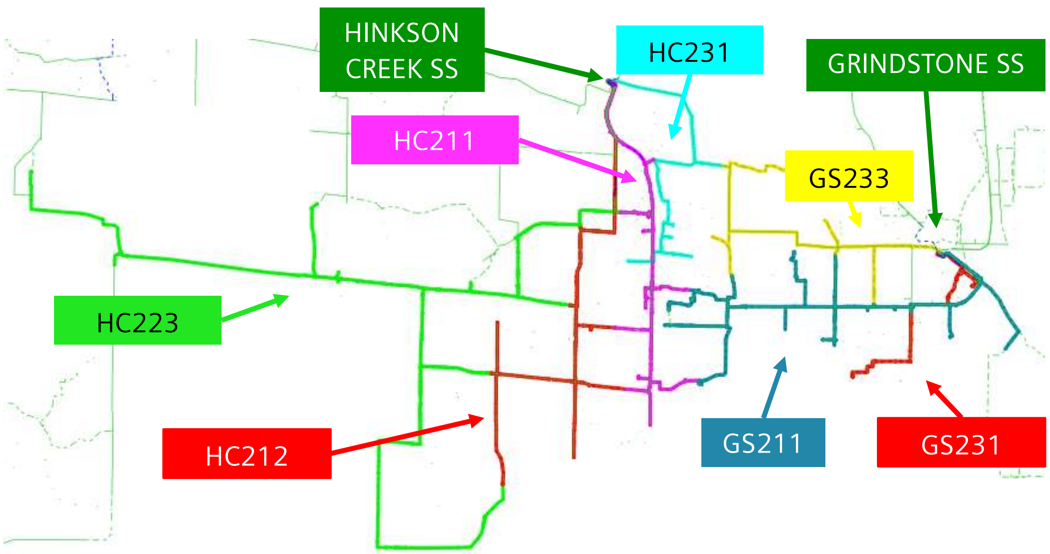


Figure 5-71 Supply area of associated feeders in Area 9

With the current configuration, the load at these feeders before any transfer is shown in Table 5-54.

Table 5-54: Feeder loads of Area 9 before any transfer or investment

Feeder	2020 P [MW]	2025 P [MW]	2030 P [MW]	2040 P [MW]
HC211	6.77	6.65	6.99	7.72
HC212	6.95	6.83	6.81	6.98
HC223	8.66	8.55	8.33	8.38
HC231	4.78	4.70	4.64	4.96
GS211	5.54	5.57	5.54	5.90
GS233	5.07	4.99	5.02	5.23
GS231	6.78	6.67	6.42	6.66

GS211 and HC231 feeders are adjacent feeders. However, an existing conductor section would be overloaded to 149,9% since it has a smaller conductor size (4/0) when GS211 is transferred to HC231 in 2025. These violations are shown in Table 5-55 and Figure 5-53. To address this issue, the overloaded section should be upgraded to 500 kcmil (Project 13, 500 kcmil CU – 0.314 mi). After this reinforcement, GS211 can be transferred to HC231 in each term without any voltage or loading violation.

Table 5-55: Violations under GS211 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Grindstone	GS211	HC231	-	149.9%	99.7%	2025

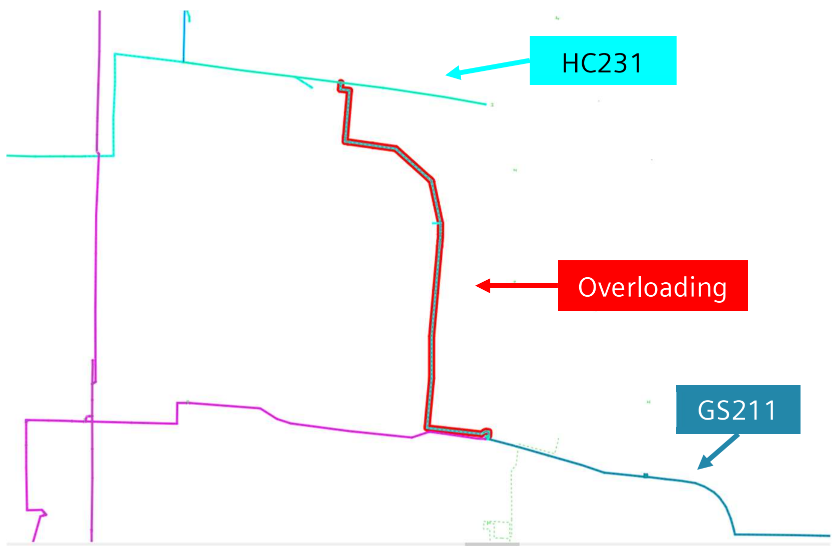


Figure 5-72 Overloading violation under GS211 emergency condition in 2025

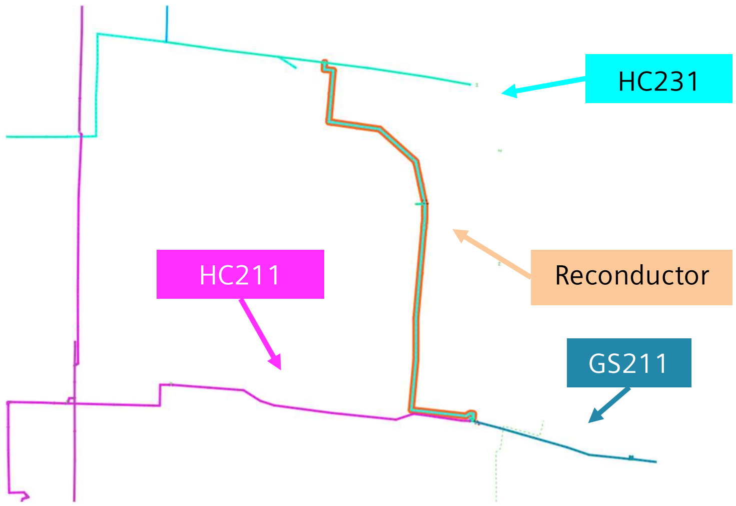


Figure 5-73 Project 12 - Reconductoring a short section between HC231 and GS211

Feeder GS231 is projected to have a section overloaded to 138.5% since it has a smaller lower conductor size (4/0) under normal operating conditions in 2025 as shown in Table 5-56 and Figure 5-74. Therefore, this section should be upgraded to 500 kcmil (Project 15, 500 kcmil CU – 0.065 mi) to address this.

Table 5-56: Violations under GS231 normal condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Grindstone	GS231	Under Normal Condition		138.5%	102.5%	2025

Figure 5-74 Overloading violation under GS231 normal condition in 2025

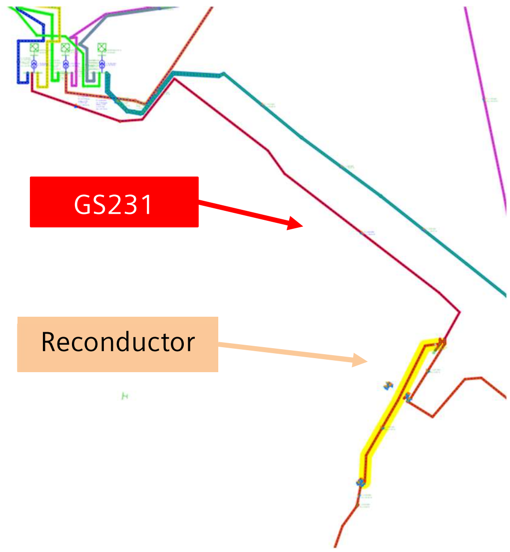


Figure 5-75 Project 15 - Reconductoring a section in GS231

Considering the reconductoring, the emergency condition of GS231 was analyzed. When GS231 is transferred to GS211, there would be an overloading violation at the substation exit to 104.5% and at a smaller conductor (4/0) section between these feeders to 177.1% in 2025. These violations are shown in Table 5-57 and Figure 5-76.

Table 5-57: Violations under GS231 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Grindstone	GS231	GS211	-	177.1%	99.5%	2025

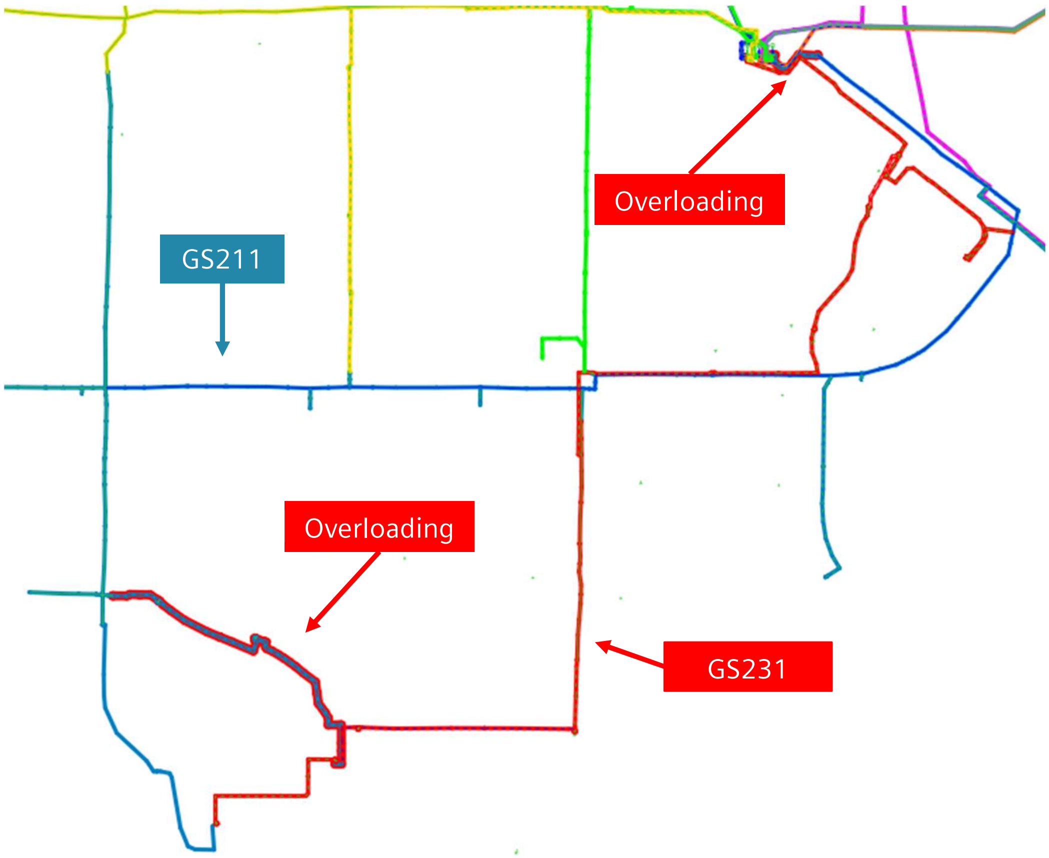


Figure 5-76 Overloading violation under GS231 emergency condition in 2025

Therefore, a new connection (Project 16 – Part 1, 500 kcmil CU – 0.326 mi) is proposed between the feeder ends of GS231 and GS211. A new route is recommended for the solution as the length of existing route is similar to new one and it creates a new path. Additionally, GS211 substation exit (Project 16 – Part 2, 500 kcmil CU – 0.065 mi) should be doubled to address overloading violation. After these reinforcements, GS231 can be transferred to GS211 in each term without any voltage or loading violation.

Additionally, doubling the GS211 substation exit would allow transferring GS222 to GS211 under an emergency condition

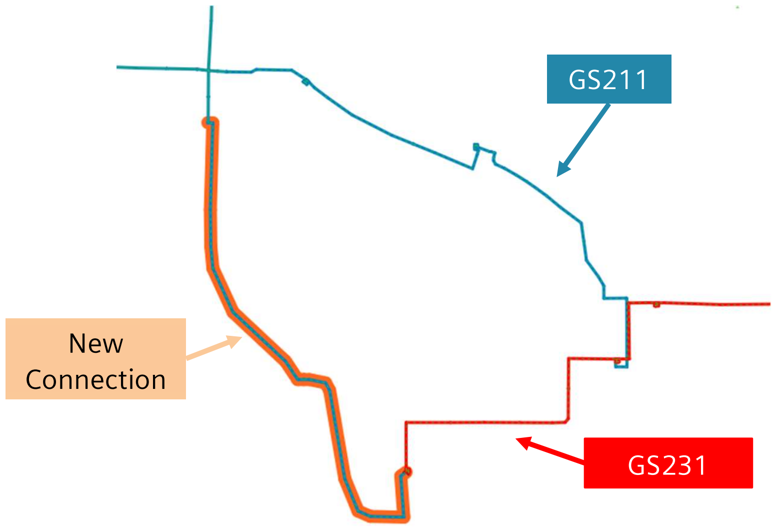


Figure 5-77 Project 16 Part 1 – New section between GS211 and GS231

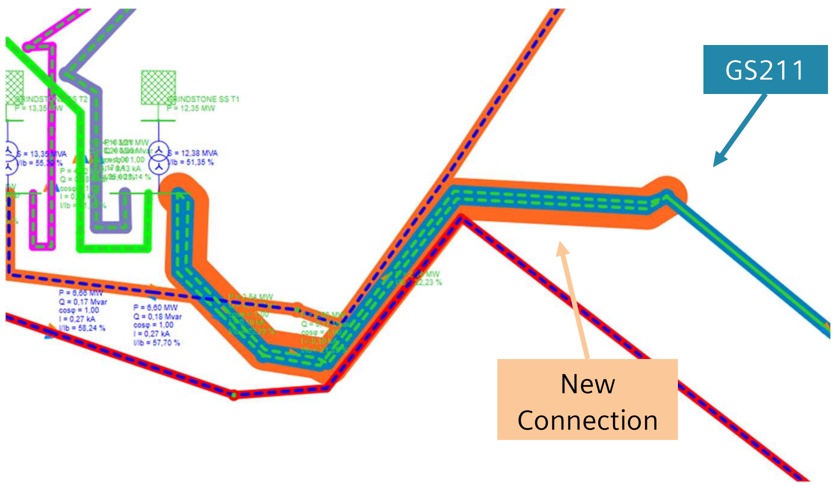


Figure 5-78 Project 16 Part 2 – Second connection at GS211 substation exit

GS233 and HC231 are adjacent feeders and GS233 can be transferred to HC231 without any loading or voltage violation in each term.

As mentioned in Section 5.5.2.5, HC223 supply area is overextended since loads in wastewater facility are supplied from HC223. When the new feeder PC232_ST is proposed from Perche Creek, this issue is also considered. By utilizing PC232_ST from Perche Creek, HC223 supply area is reconfigured by transferring wastewater facility to new feeder. This reconfiguration is also required to create room for emergency conditions.

Although HC212 and new proposed feeder PC231_ST are adjacent feeders to HC223, they are fairly loaded and none of them individually has enough capacity to transfer HC223 load. Additionally, HC223 is close to CWL service territory border and there are not many options for backup purposes. Therefore, both HC212 and PC231_ST are proposed to supply HC223 load partially under HC223 emergency supply and this can be achieved without any loading or voltage violation in each term.

HC212 feeder has similar conditions to HC223. It is fairly loaded and there are not many adjacent feeders to provide backup because its location. The adjacent feeders HC211 and HC223 can supply HC212 load partially under HC212 emergency, without any loading or voltage violation in each term. Transferring of wastewater facility from HC223 to PC232_ST should be done in advance, and it is a prerequisite for this backup configuration.

HC211 feeder is fairly loaded. HC231 and GS211 can supply HC211 load partially when HC211 is under emergency without any loading or voltage violation in any term.

With the current configuration, HC231 can be transferred to adjacent feeder GS231 without having any loading or voltage violation in each term.

The reconfiguration of supply areas and related switching for Area 9 is illustrated in Figure 5-79. The new loads for the associated feeders are shown in Table 5-58.

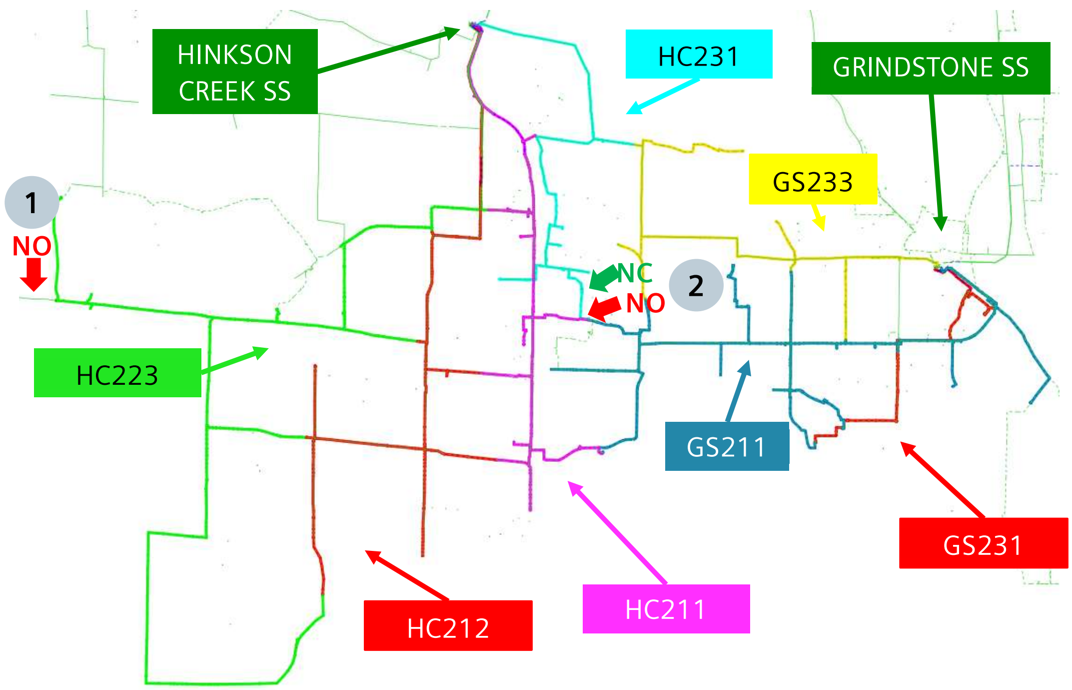


Figure 5-79 Proposed supply area for Area 9 in 2025

Table 5-58: Feeder loads of Area 9 after supply area reconfiguration

Feeder	2025 P [MW]	2030 P [MW]	2040 P [MW]
HC211	6.65	6.99	7.72
HC212	6.83	6.81	6.98
HC223	6.23	6.10	6.20
HC231	5.23	5.17	5.52
GS211	5.04	5.00	5.34
GS233	4.99	5.01	5.23
GS231	6.66	6.42	6.65

New capacitor banks are proposed to improve power factor at various locations. They are sized considering the preference to prevent injection of reactive power at the substation back to transmission. They are listed in Table 5-59 according to sizes and in service dates. Additionally, location of capacitor banks is shown in Figure 5-80.

Table 5-59: New capacitor banks for Area 9

Feeder Name	2025 300 kVAr	 600 kVAr	 900 kVAr
HC211	-	-	-
HC212	-	-	-
HC223	-	-	-
HC231	1	-	-
GS211	-	-	-
GS233	-	1	1
GS231	-	1	-

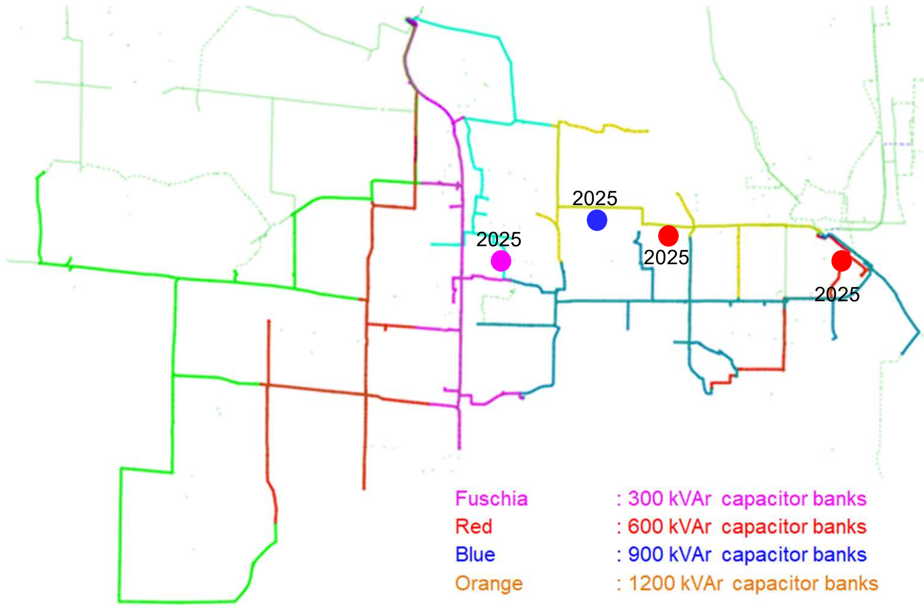


Figure 5-80 New capacitor banks in Area 9

The reinforced proposed system was analyzed under emergency conditions. Table 5-60 summarizes for feeders HC211, HC212, HC223, HC231, GS211, GS231 and GS233 what is the recommended backup feeder(s) for each term. These back up feeders can accept all load from main feeder (with the contingency) without loading or voltage violations.

Table 5-60: Back-up feeders of Area 9 for each term

Substation	Main Feeder	2025 Back-Up Feeder-1	2025 Back-Up Feeder-2	2030 Back-Up Feeder-1	2030 Back-Up Feeder-2	2040 Back-Up Feeder-1	2040 Back-Up Feeder-2
Grindstone	GS211	HC231	-	HC231	-	HC231	-
Grindstone	GS231	GS211	-	GS211	-	GS211	-
Grindstone	GS233	HC231	-	HC231	-	HC231	-
Hinkson Creek	HC211	HC231	GS211	HC231	GS211	HC231	GS211
Hinkson Creek	HC212	HC211	HC223	HC211	HC223	HC211	HC223
Hinkson Creek	HC223	PC231_ST	HC212	PC231_ST	HC212	PC231_ST	HC212
Hinkson Creek	HC231	GS211	-	GS211	-	GS211	-

5.5.2.10 Area 10 – Grindstone, Hinkson Creek and Rebel Hill Area

The Area 10 is shown in Figure 5-81 and includes the following feeders:

- From Grindstone: GS213 and GS232
- From Hinkson Creek: HC232

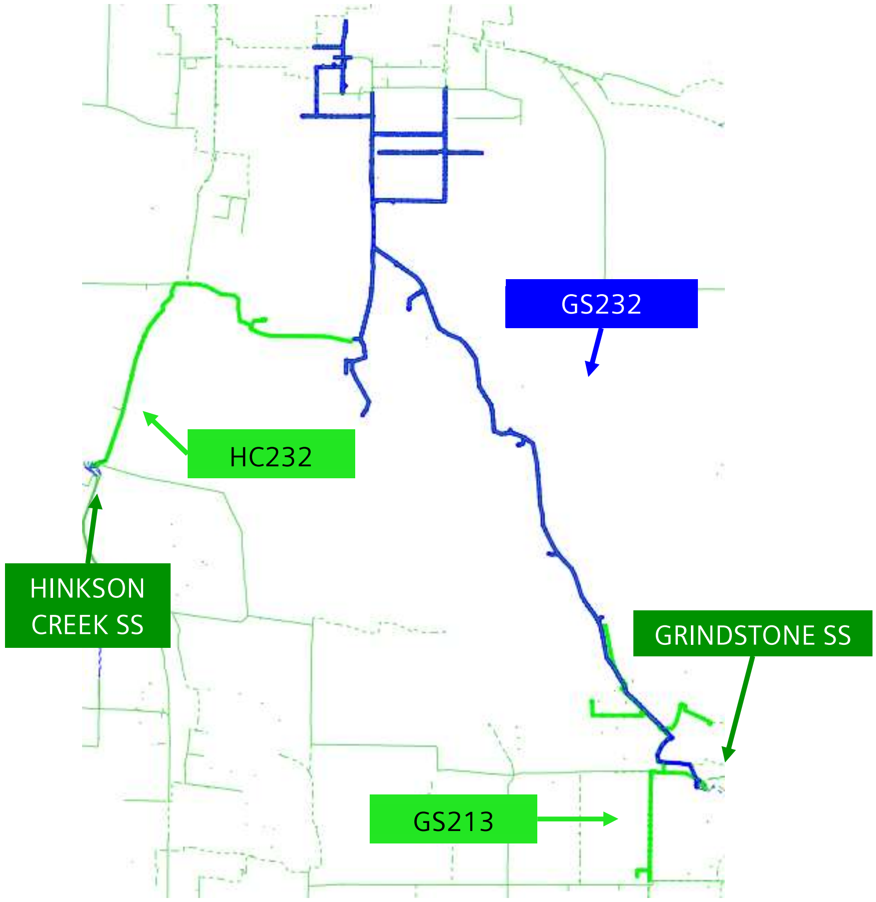


Figure 5-81 Supply area of associated feeders in Area 10

With the current configuration, the load at these feeders before any transfer is shown in Table 5-61.

Table 5-61: Feeder loads of Area 10 before any transfer or investment

Feeder	2020 P [MW]	2025 P [MW]	2030 P [MW]	2040 P [MW]
GS232	8.17	8.14	8.04	8.69
HC232	3.81	3.75	3.61	3.53
GS213	4.17	4.10	4.08	4.32

GS232 feeder supply area extends far northwest of Grindstone and has connections to feeders from Rebel Hill and Power Plant. Given that it is not possible to expand the transformation capacity at Grindstone the investments for this area took into consideration reducing Grindstone load by transferring part of this feeder load to Rebel Hill and create room for emergency. This is detailed below.

From contingency perspective, when GS232 is transferred RH212, there would be an overloading violation at substation exit and along the feeder to 147.4% and voltage violation mainly on GS232 feeder to 96.5%. These violations are shown in Table 5-62, Figure 5-82 and Figure 5-83.

Table 5-62: Violations under GS232 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Grindstone	GS232	RH212	-	147.4%	96.5%	2025

Figure 5-82 Overloading violation under GS232 emergency condition in 2025

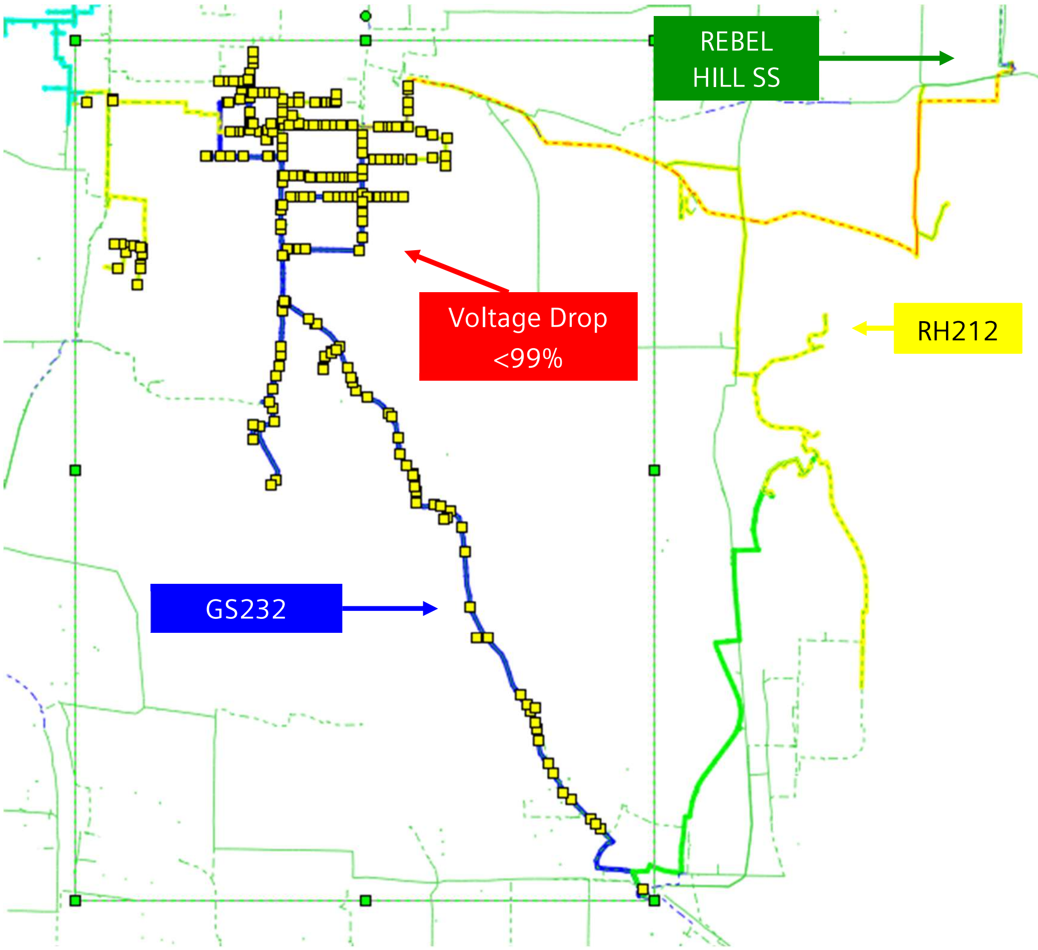


Figure 5-83 Voltage violation under GS232 emergency condition in 2025

Considering RH212 supply area in addition to violations mentioned above, a new feeder RH231_ST (Project 20, 500 kcmil CU – 1.389 mi) is proposed in 2025 to take some load of GS2320. This new feeder will connect to the new transformer at Rebel Hill. After reconfiguration of supply area, GS232 can be transferred to HC232 without any loading or voltage violation in each term.

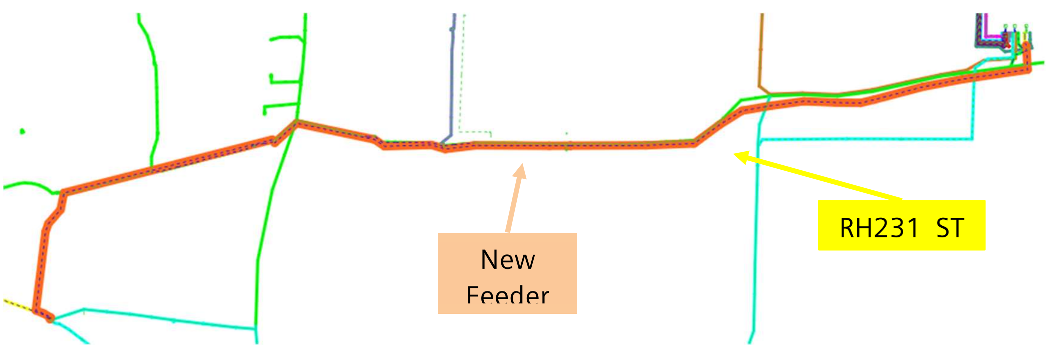


Figure 5-84 Project 20 - New feeder RH231_ST

HC232 and GS232 are adjacent feeders. HC232 can be transferred to adjacent feeder GS232 without having any loading or voltage violation in each term.

GS213 supply area is separated in two main routes going to the north and to the south. GS213 can be transferred to GS211 by using the connection to the south. On the other side, when GS211 is transferred to GS232 by using the connection to the north, there would be an overloading issue to 114.3% along the connection between the feeders in 2025. These violations are shown in Table 5-63 and Figure 5-85.

Table 5-63: Violations under GS213 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Grindstone	GS213	GS232	-	114.3%	101.4%	2025

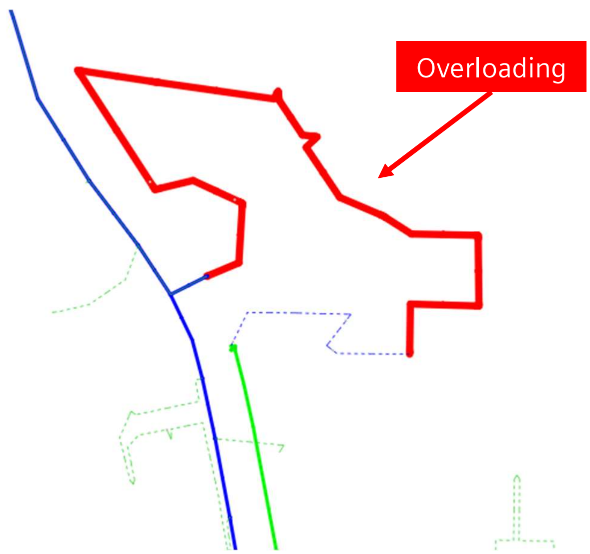


Figure 5-85 Overloading violation under GS213 emergency condition in 2025

Therefore, a short new connection (Project 14, 500 kcmil CU – 0.007 mi) between GS232 and GS213 is proposed. With this new connection between the feeders, GS213 can be transferred to GS232 without having any loading or voltage violation in each term.

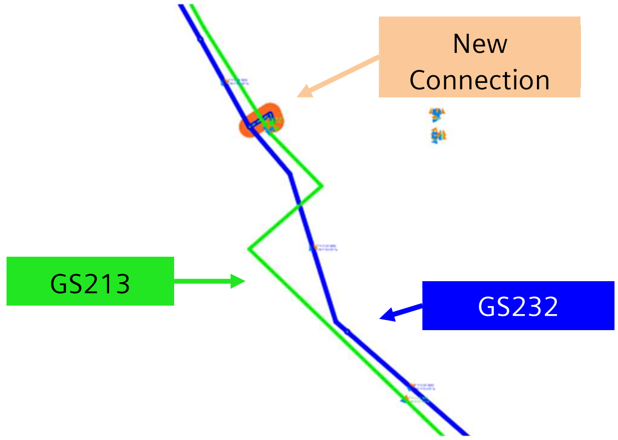


Figure 5-86 Project 14 - New connection between GS232 and GS213

Reconfiguration of supply areas and related switching for Area 8 is illustrated in Figure 5-87. The new loads for the associated feeders are shown in Table 5-64.

Table 5-64: Feeder loads of Area 10 after supply area reconfiguration

Feeder	2025 P [MW]	2030 P [MW]	2040 P [MW]
RH231_ST	8.12	7.96	8.01
GS232	4.70	4.68	5.33
HC232	3.75	3.61	3.53
GS213	4.10	4.08	4.32

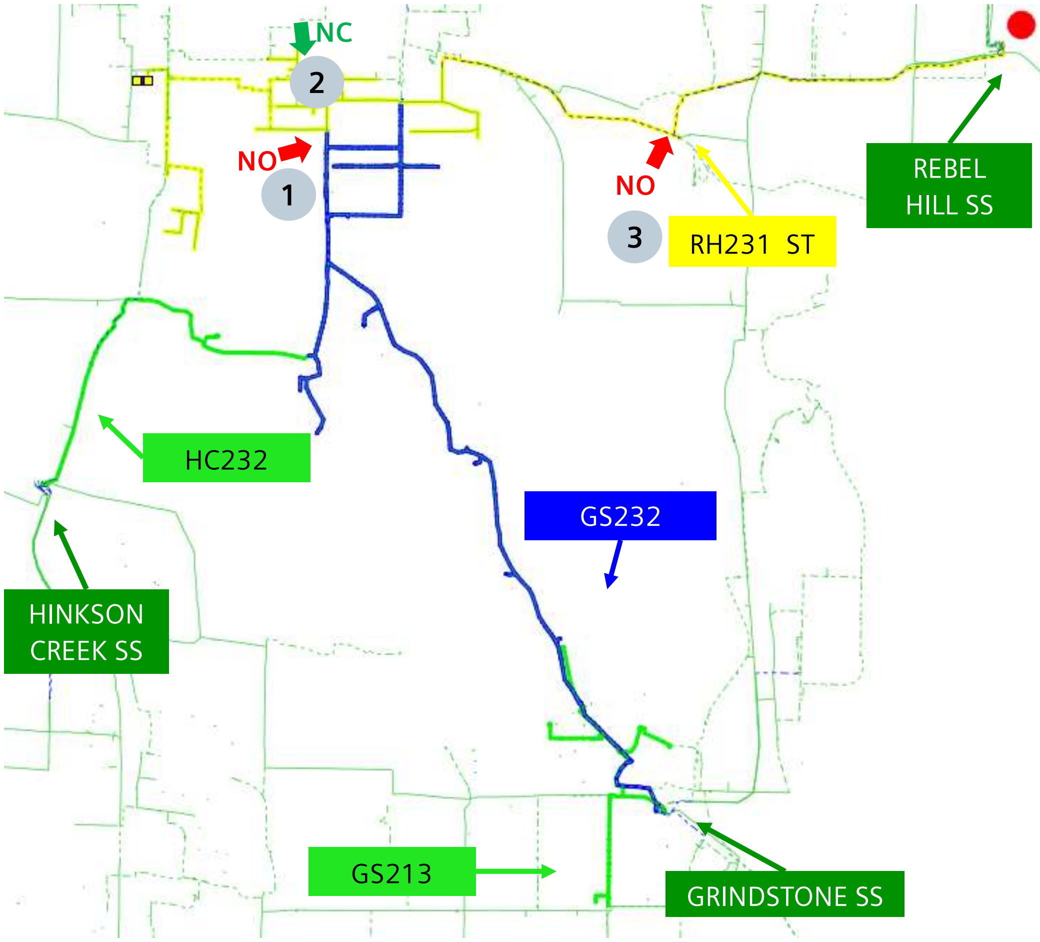


Figure 5-87 Proposed supply area for Area 10 in 2025

New capacitor banks are proposed to improve power factor at various locations. They are sized considering the preference to prevent injection of reactive power at the substation back to transmission. They are listed in Table 5-65 according to sizes and in service dates. Additionally, location of capacitor banks is shown in Figure 5-35.

Table 5-65: New capacitor banks for Area 10

Feeder Name	2025 900 kVAr
RH231_ST	-
GS232	-
HC232	1
GS213	-

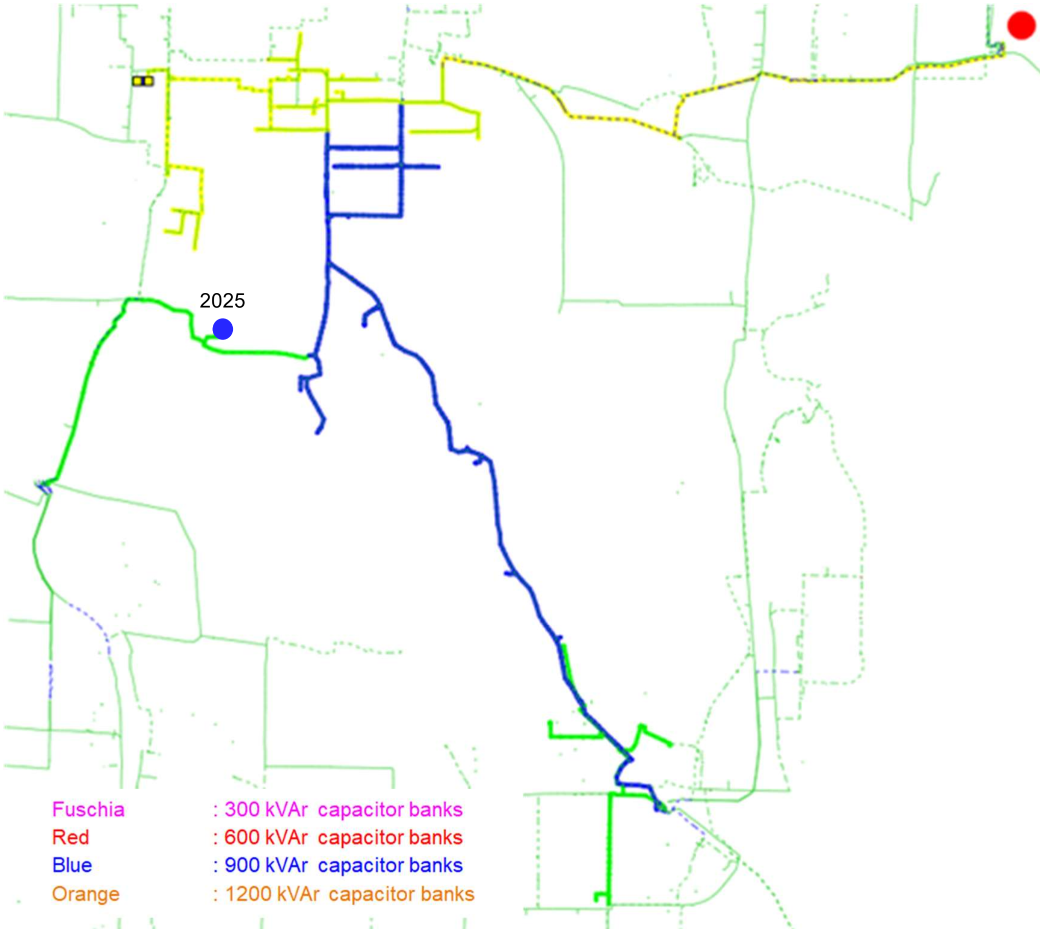


Figure 5-88 New capacitor banks in Area 10

The reinforced proposed system was analyzed under emergency conditions. Table 5-66 summarizes for feeders GS232, HC232, GS213 and RH231_ST what is the recommended backup feeder(s) for each term. These back up feeders can accept all load from main feeder (with the contingency) without loading or voltage violations.

Table 5-66: Back-up feeders of Area 10 for each term

Substation	Main Feeder	2025 Back-Up Feeder-1	2025 Back-Up Feeder-2	2030 Back-Up Feeder-1	2030 Back-Up Feeder-2	2040 Back-Up Feeder-1	2040 Back-Up Feeder-2
Grindstone	GS213	GS232	-	GS232	-	GS232	-
Grindstone	GS232	HC232	-	HC232	-	HC232	-
Hinkson Creek	HC232	GS232	-	GS232	-	GS232	-
Rebel Hill	RH231_ST	PP214	GS232	PP214	GS232	PP214	GS232

5.5.2.11 Area 11 – Grindstone and Rebel Hill Area

The Area 11 is shown in Figure 5-89 and includes the following feeders:

- From Grindstone: GS212, GS221, GS223 and GS222
- From Rebel Hill: RH212

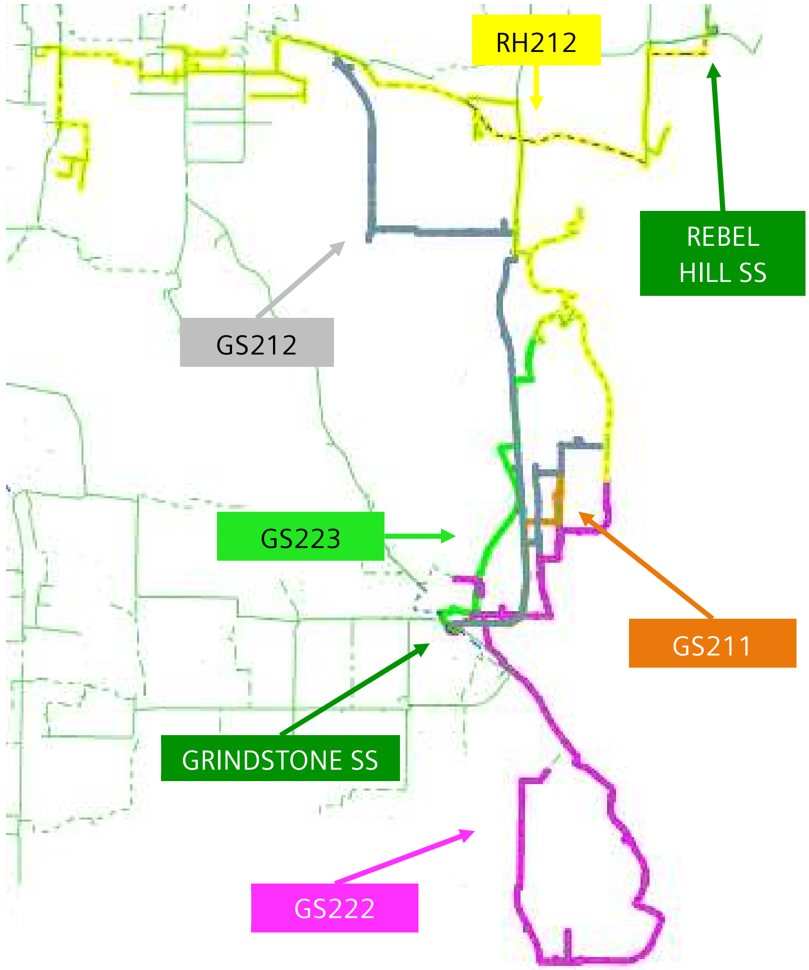


Figure 5-89 Supply area of associated feeders in Area 11

With the current configuration, the load at these feeders before any transfer is shown in Table 5-67.

Table 5-67: Feeder loads of Area 11 before any transfer or investment

Feeder	2020 P [MW]	2025 P [MW]	2030 P [MW]	2040 P [MW]
RH212	7.37	8.01	8.19	9.16
GS212	5.19	5.10	5.01	5.09
GS221	3.38	3.32	3.19	3.12
GS223	2.06	2.03	1.95	2.18
GS222	5.61	7.99	9.33	11.47

As presented in Section 5.5.2.10, a new feeder RH231_ST (Project 20) is proposed connecting to new transformer in Rebel Hill in 2025. RH231_ST is to partially take loads from RH212 mainly to the west. Thus, the remaining RH212 goes mainly to the south where there are lots of adjacent feeders connected to Grindstone. As RH212 transferred load to new feeder, RH212 has a room to take some load from

Grindstone to prevent overloading of the Grindstone substation transformers. Therefore, some sections of GS212 are transferred to RH212. After reconfiguration of RH212 supply area, RH212 can be transferred to GS212 without any loading or voltage violation in each term.

GS212 can be transferred to RH212 without any loading or voltage violation in each term.

GS223 and RH212 are adjacent feeders. GS223 can be transferred to RH212 without any loading or voltage violation in each term.

When GS222 is transferred to GS211 which is proposed to have its substation exit doubled, there would not be any loading or voltage violation in 2025 and 2030. However, in 2040 Grindstone T1 would be overloaded. Reconfiguration of supply area is a solution to create required room for emergency cases. Once GS222 supply area is examined, it can be separated into two main routes to the northeast and south. Northeast part of the GS222 is transferred to GS221. After this reconfiguration of supply area, GS222 can be transferred to GS221 without any loading or voltage violation in each term.

Additionally, according to new supply area of GS221, it can be transferred to GS212 without any loading or voltage violation in each term.

Reconfiguration of supply areas and related switching for Area 9 is illustrated in Figure 5-90. The new loads for the associated feeders are shown in Table 5-68.

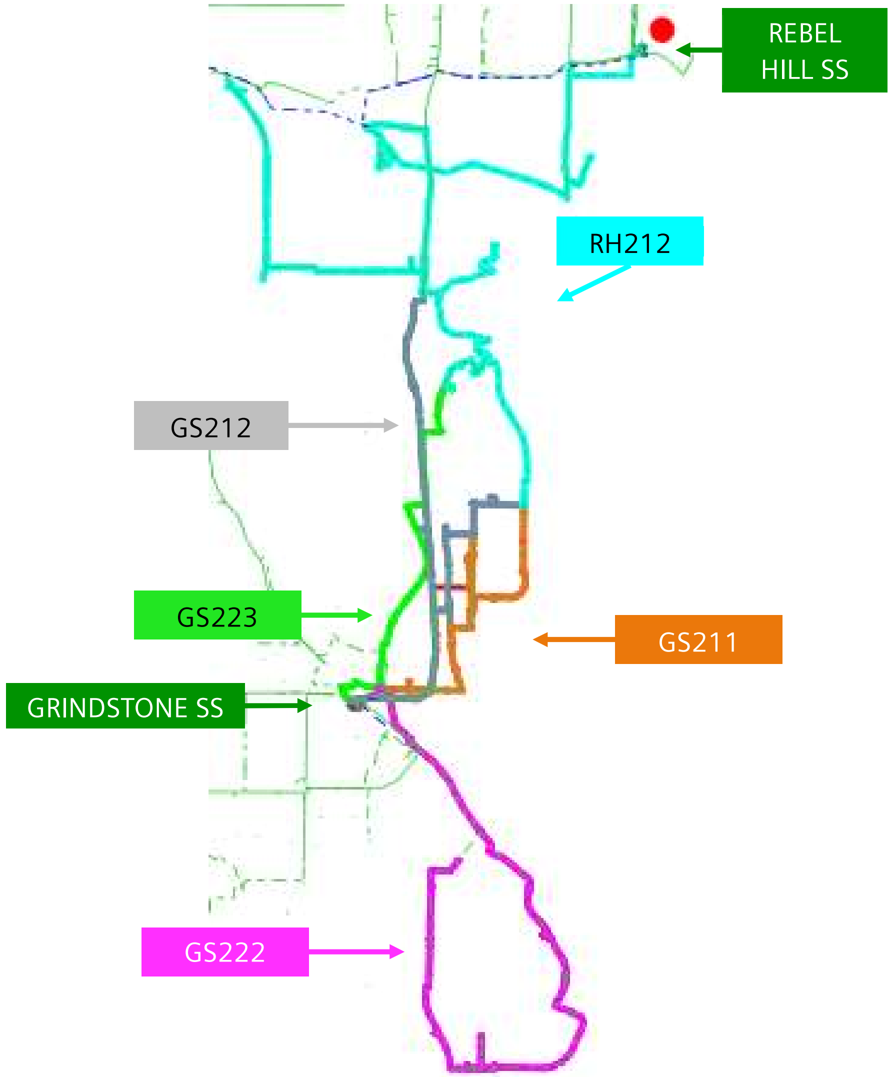


Figure 5-90 Proposed supply area for Area 11 in 2025

Table 5-68: Feeder loads of Area 11 after supply area reconfiguration

Feeder	2025 P [MW]	2030 P [MW]	2040 P [MW]
RH212	5.16	5.40	6.36
GS212	3.21	3.14	3.16
GS221	6.60	6.40	6.31
GS223	2.03	1.95	2.18
GS222	4.72	6.13	8.28

New capacitor banks are proposed to improve power factor at various locations. They are sized considering the preference to prevent injection of reactive power at the substation back to transmission. They are listed in Table 5-69 according to sizes and in service dates. Additionally, location of capacitor banks is shown in Figure 5-91.

Table 5-69: New capacitor banks for Area 11

Feeder Name	2025 600 kVAr	2025 900 kVAr	2025 1200 kVAr	2030 900 kVAr	2040 1200 kVAr
RH212	-	-	-	-	-
GS212	-	-	-	-	-
GS221	-	-	-	-	-
GS223	-	1	-	-	-
GS222	1	-	1	1	1

Figure 5-91 New capacitor banks in Area 11

The reinforced proposed system was analyzed under emergency conditions. Table 5-70 summarizes for feeders for GS212, GS221, GS222, GS223 and RH212 what is the recommended backup feeder(s) for each term. These back up feeders can accept all load from main feeder (with the contingency) without loading or voltage violations.

Table 5-70: Back-up feeders of Area 11 for each term

Substation	Main Feeder	2025 Back-Up Feeder-1	2025 Back-Up Feeder-2	2030 Back-Up Feeder-1	2030 Back-Up Feeder-2	2040 Back-Up Feeder-1	2040 Back-Up Feeder-2
Grindstone	GS212	RH212	-	RH212	-	RH212	-
Grindstone	GS221	GS212	-	GS212	-	GS212	-
Grindstone	GS222	GS211	-	GS211	-	GS211	-
Grindstone	GS223	RH212	-	RH212	-	RH212	-
Rebel Hill	RH212	GS212	-	GS212	-	GS212	-

5.5.2.12 Area 12 – Rebel Hill Area

The Area 12 is shown in Figure 5-92 and includes only feeders at this substation:

- RH214 and RH224

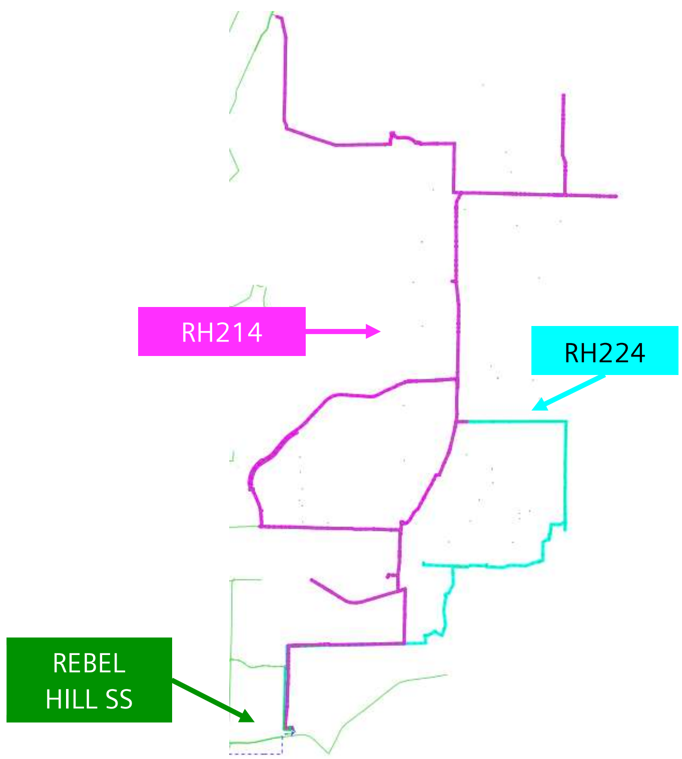


Figure 5-92 Supply area of associated feeders in Area 12

With the current configuration, the load at these feeders before any transfer is shown in Table 5-71.

Table 5-71: Feeder loads of Area 12 before any transfer or investment

	2020	2025	2030	2040

Feeder	P [MW]	P [MW]	P [MW]	P [MW]
RH214	6.05	6.11	6.23	7.12
RH224	6.16	6.06	6.89	8.35

RH214 and RH224 supply to north and northeast side of the substation and they are adjacent feeders. However, they cannot provide a full back up to each other as they are fairly loaded. Additionally, their supply area close to CWL service territory border and adjacent feeders are limited such as BD213 for RH214.

When RH224 is transferred to RH214, there would be an overloading violation as 108.3% along the feeder and at substation exit as well in 2025. These violations are shown in Table 5-72 and Figure 5-93.

Table 5-72: Violations under RH224 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Rebel Hill	RH224	RH214	-	108.4%	99.6%	2025

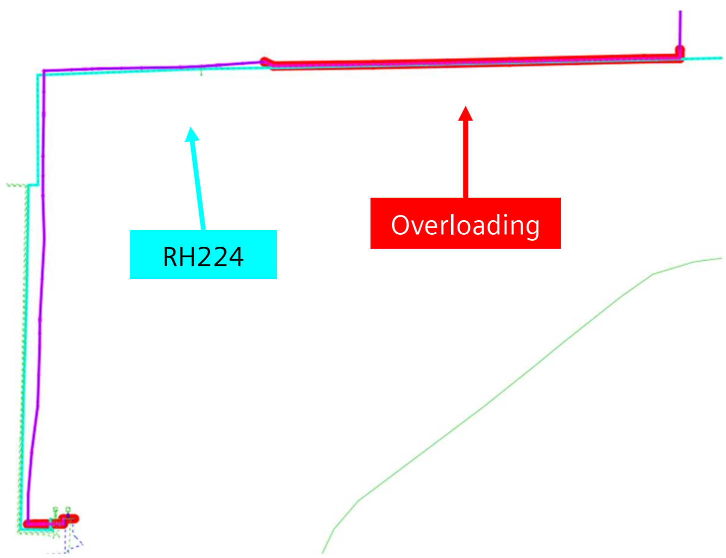


Figure 5-93 Overloading violation under RH224 emergency condition in 2025

When RH214 is transferred to BD213, there would be an overloading violation as 108.1% at substation exit and along the feeder and voltage violation almost entire loads connected to RH214. These violations are shown in Table 5-73 and Figure 5-93.

Table 5-73: Violations under RH214 emergency condition in 2025

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
Rebel Hill	RH214	BD213	-	108.1%	97.9%	2025

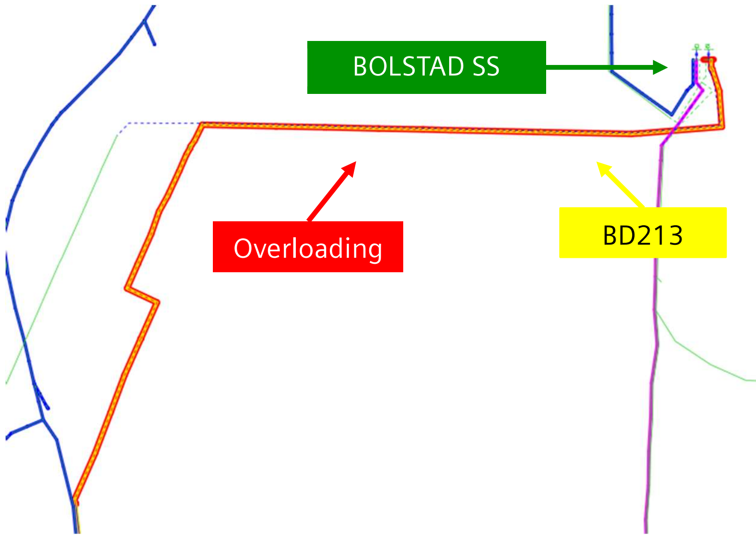


Figure 5-94 Overloading violation under RH214 emergency condition in 2025

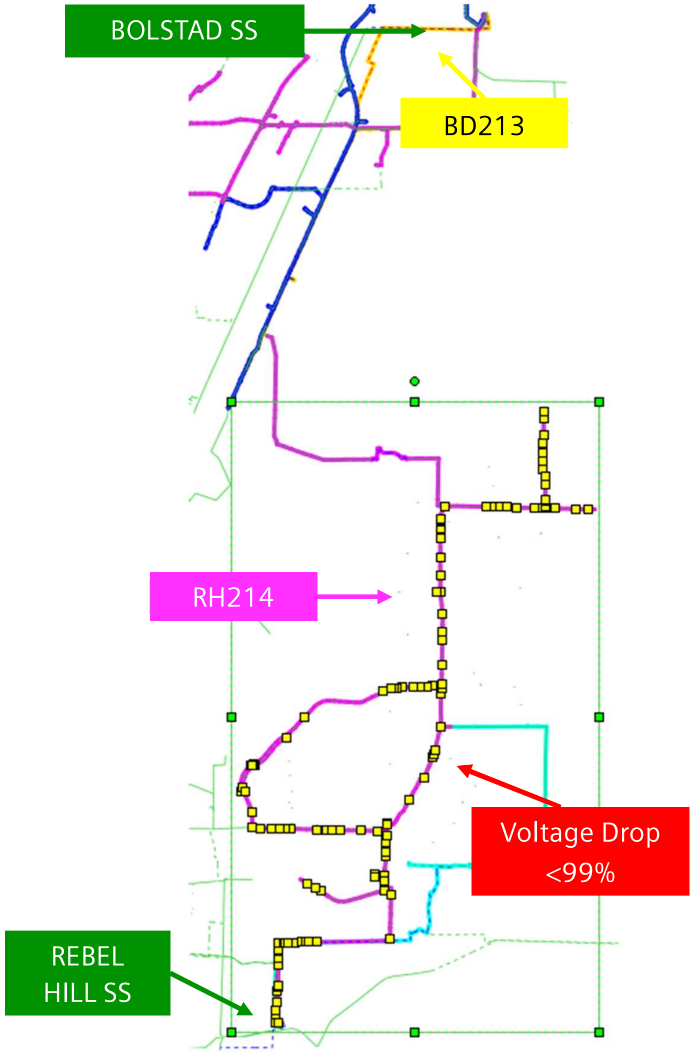


Figure 5-95 Voltage violation under RH214 emergency condition in 2025

Therefore, a new feeder RH232_ST (Project 17, 500 kcmil CU – 2.188 mi) is proposed in 2025 to provide capacity to use during emergencies. This feeder will connect to the new transformer at Rebel Hill. After RH232_ST is built, some part of RH214 will be transferred to RH232_ST and a minor change is proposed for RH224 for operation easiness. After reconfiguration of the supply area, RH214 and RH224 can be transferred to RH232_ST without any voltage or loading violation in each term.

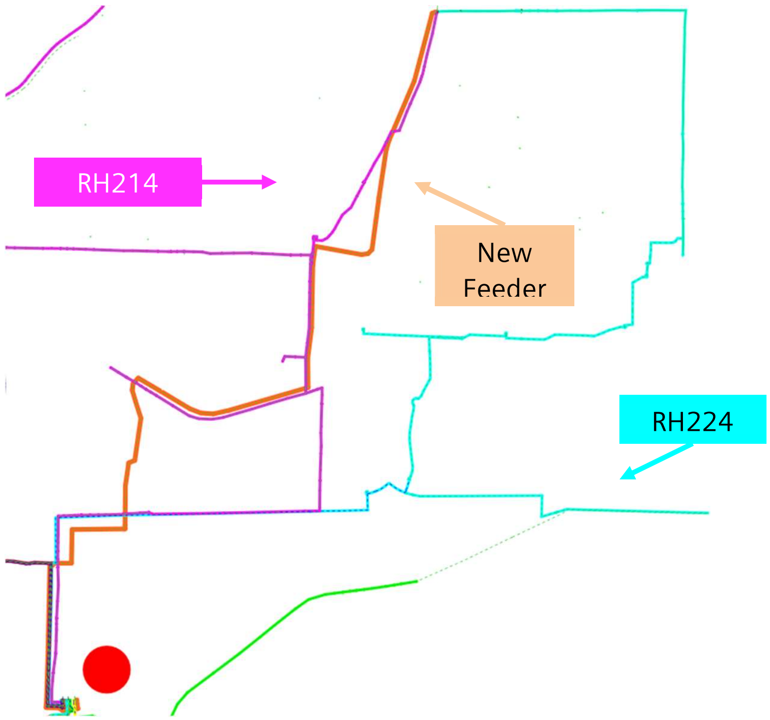


Figure 5-96 Project 17 - New feeder RH232_ST

Reconfiguration of supply areas and related switching for Area 8 is illustrated in Figure 5-97. The new loads for the associated feeders are shown in Table 5-74.

Table 5-74: Feeder loads of Area 12 after supply area reconfiguration

Feeder	2025 P [MW]	2030 P [MW]	2040 P [MW]
RH214	3.30	3.52	4.23
RH224	6.06	6.89	8.34
RH232_ST	2.78	2.68	2.85

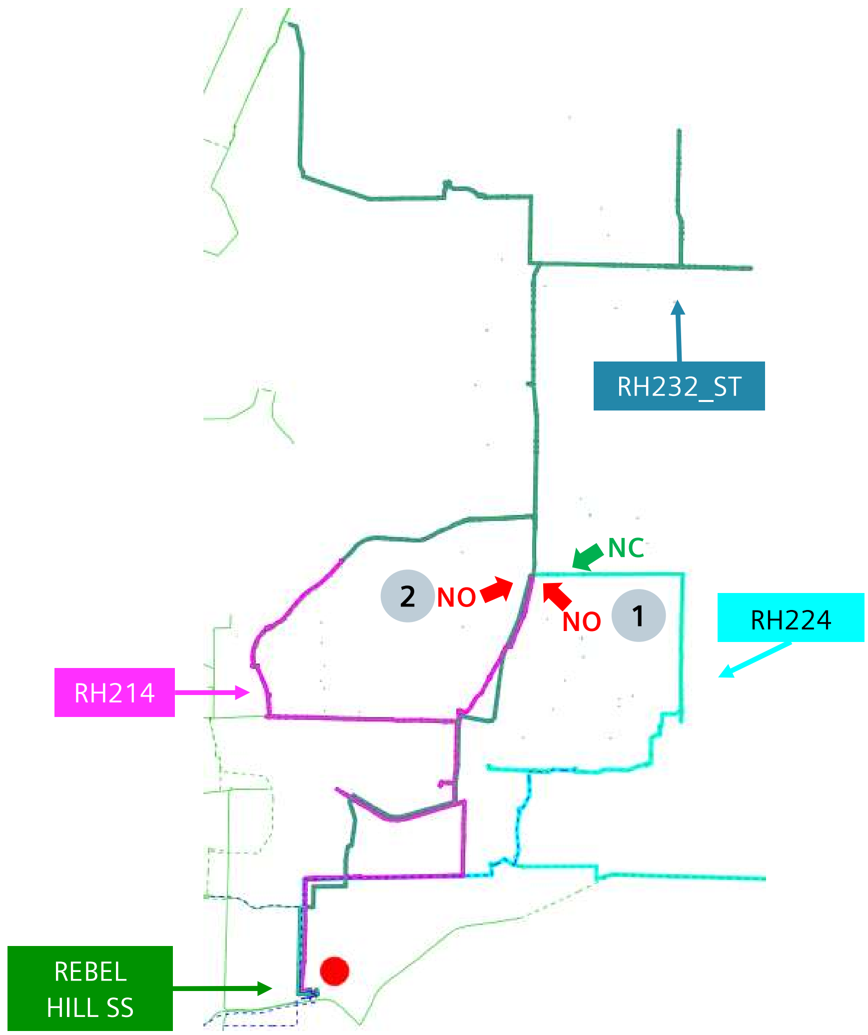


Figure 5-97 Proposed supply area for Area 12 in 2025

Reactive power consumptions and power factors of associated feeders were evaluated and no need for additional capacitor banks was identified.

The reinforced proposed system was analyzed under emergency conditions. Table 5-75 summarizes for feeders RH214, RH224 and RH232_ST what is the recommended backup feeder(s) for each term. These back up feeders can accept all load from main feeder (with the contingency) without loading or voltage violations.

Table 5-75: Back-up feeders of Area 12 for each term

Substation	Main Feeder	2025 Back-Up Feeder-1	2025 Back-Up Feeder-2	2030 Back-Up Feeder-1	2030 Back-Up Feeder-2	2040 Back-Up Feeder-1	2040 Back-Up Feeder-2
Rebel Hill	RH214	RH232_ST	-	RH232_ST	-	RH232_ST	-
Rebel Hill	RH224	RH232_ST	-	RH232_ST	-	RH232_ST	-
Rebel Hill	RH232_ST	BD213	-	BD213	-	BD213	-

5.5.2.13 Area 13 – Rebel Hill and Power Plant Area

The Area 13 is shown in Figure 5-98 and includes the following feeders:

- From Rebel Hill: RH211, RH221 and RH222
- From Power Plant: PP222 and PP231

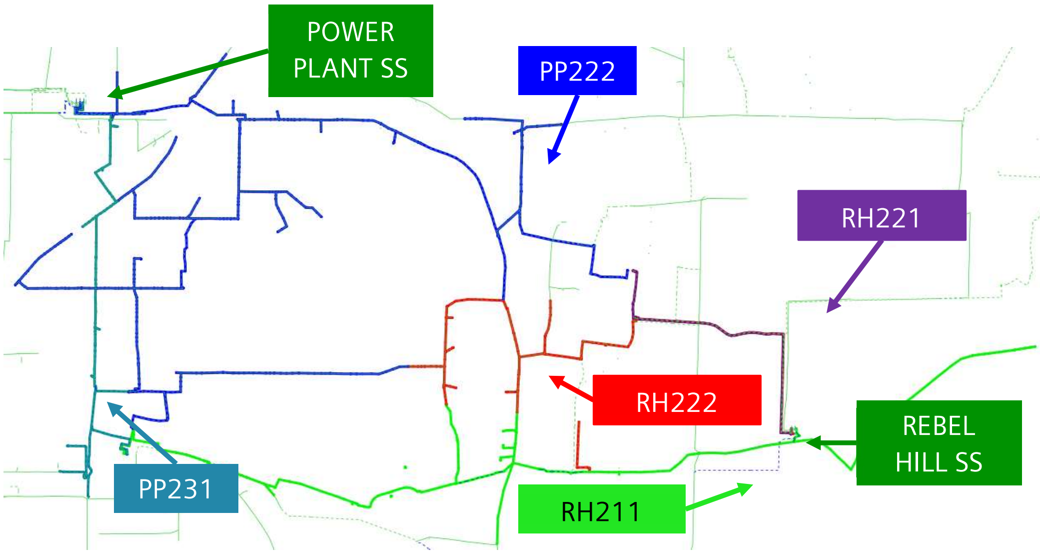


Figure 5-98 Supply area of associated feeders in Area 13

With the current configuration, the load at these feeders before any transfer is shown in Table 5-76.

Table 5-76: Feeder loads of Area 13 before any transfer or investment

Feeder	2020 P [MW]	2025 P [MW]	2030 P [MW]	2040 P [MW]
PP222	5.27	5.22	5.42	5.98
PP231	5.44	5.69	5.70	5.90
RH221	3.27	3.36	3.35	3.44
RH222	2.72	2.88	2.90	3.02
RH211	7.94	7.98	7.87	8.09

With the provided information, Power Plant has not enough space for an expansion in the future. However, the load growth in the supply area of Power Plant would result in Power Plant transformers to overload under emergency conditions. When one of the transformers at Power Plant is out of service, the others would be overloaded to 109.1% as shown in Table 5-77.

Table 5-77: Violations under Power Plant transformer emergency condition in 2025

Substation	Substation Load [MVA]	Number of Transformer	Transformer Capacity [MVA]	N-1 Loading [%]	Appearance Year
Power Plant	50.4	3	23.1	109.1%	2025

Therefore, to address this load from Power Plant is transferred to Rebel Hill which has a new transformer in 2025.

RH221 and RH222 feeders are lightly loaded and are good candidates to transfer load from Power Plant to Rebel Hill. PP222 and RH221 mainlines are very close to each other but not connected. A short new section (Project 18, 500 kcmil CU – 0.06 mi) is proposed to connect these feeders via mainlines. RH222 has already connections to PP222, and load can be transferred by only switching. There is no additional requirement for this reconfiguration. After supply area reconfiguration, PP222 can be transferred to RH222 and RH221 in 2025.

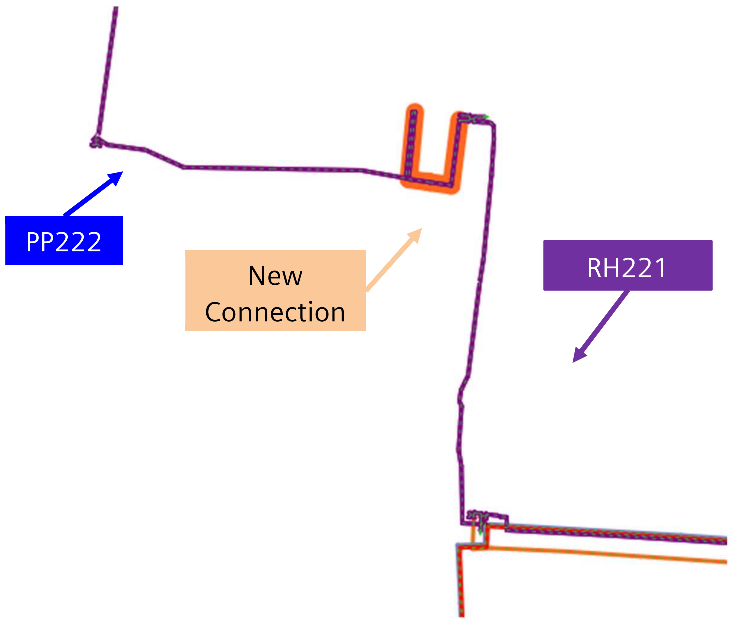


Figure 5-99 Project 18 - New section between PP222 and RH221

According to the new configuration, PP231 and RH222 feeder are adjacent feeders and PP231 can be transferred to RH222 in each term without any loading or voltage violation.

RH211 is fairly loaded to be transferred to only one adjacent feeder. Thus, two adjacent feeders will be required to backup RH211. RH211 can be transferred to RH222 and PP231 partially in each term without any loading or voltage violation.

Reconfiguration of supply areas and related switching for Area 9 is illustrated in Figure 5-100. The new loads for the associated feeders are shown in Table 5-78.

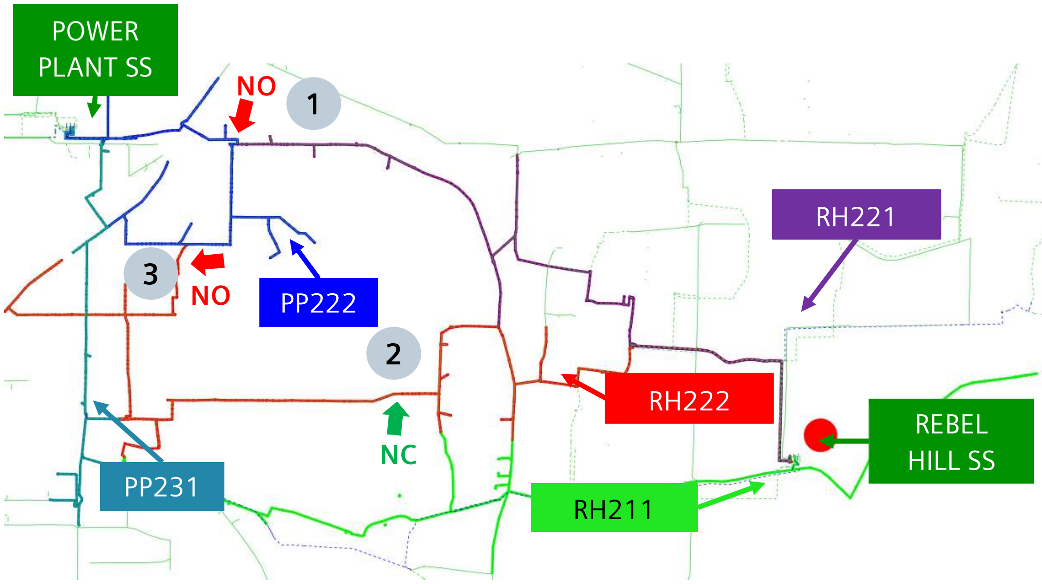


Figure 5-100 Proposed supply area for Area 13 in 2025

Table 5-78: Feeder loads of Area 13 after supply area reconfiguration

Feeder	2025 P [MW]	2030 P [MW]	2040 P [MW]
PP222	1.63	1.79	2.07
PP231	5.69	5.70	5.90
RH221	4.67	4.77	5.11
RH222	5.17	5.12	5.27
RH211	7.98	7.86	8.09

New capacitor banks are proposed to improve power factor at various locations. They are sized considering the preference to prevent injection of reactive power at the substation back to transmission. They are listed in Table 5-79 according to sizes and in service dates. Additionally, location of capacitor banks is shown in Figure 5-101.

Table 5-79: New capacitor banks for Area 13

Feeder Name	2025 300 kVAr	2025 600 kVAr	2025 900 kVAr	2025 1200 kVAr	2040 300 kVAr
PP222	-	1	-	-	1
PP231	-	-	-	-	-
RH221	1	-	1	1	1
RH222	-	-	-	-	-
RH211	1	-	-	1	-

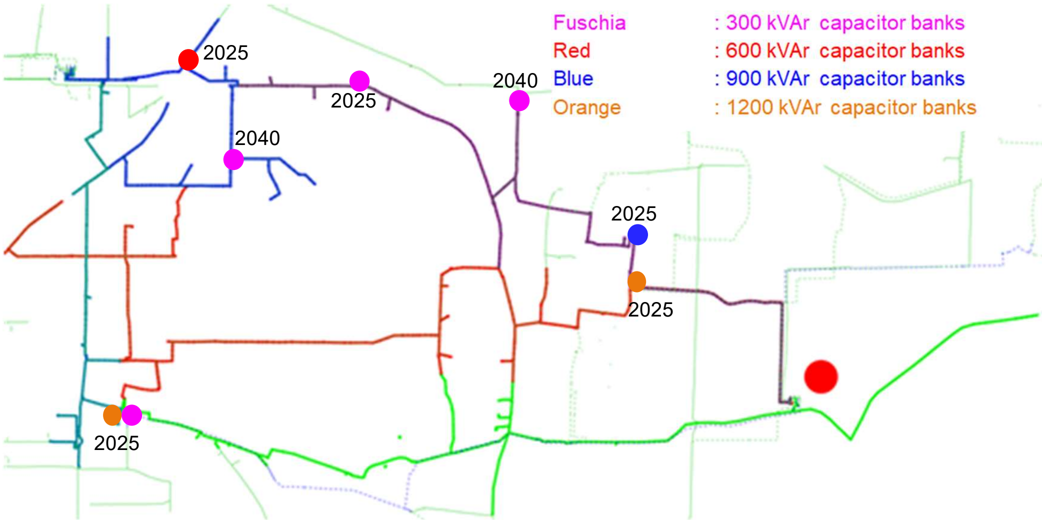


Figure 5-101 New capacitor banks in Area 13

The reinforced proposed system was analyzed under emergency conditions Table 5-80 summarizes for feeders PP222, PP231, RH211, RH221 and RH222 what is the recommended backup feeder(s) for each term. These back up feeders can accept all load from main feeder (with the contingency) without loading or voltage violations.

Table 5-80: Back-up feeders of Area 13 for each term

Substation	Main Feeder	2025 Back-Up Feeder-1	2025 Back-Up Feeder-2	2030 Back-Up Feeder-1	2030 Back-Up Feeder-2	2040 Back-Up Feeder-1	2040 Back-Up Feeder-2
Power Plant	PP222	RH222	-	RH222	-	RH222	-
Power Plant	PP231	RH222	-	RH222	-	RH222	-
Rebel Hill	RH211	RH222	PP231	RH222	PP231	RH222	PP231
Rebel Hill	RH221	PP222	-	PP222	-	PP222	-
Rebel Hill	RH222	PP222	-	PP222	-	PP222	-

5.5.2.14 Area 14 – Blue Ridge and Rebel Hill Area

The Area 14 is shown in Figure 5-102 and includes the following feeders:

- From Blue Ridge: BR211, BR213 and BR222
- From Rebel Hill: RH213 and RH223

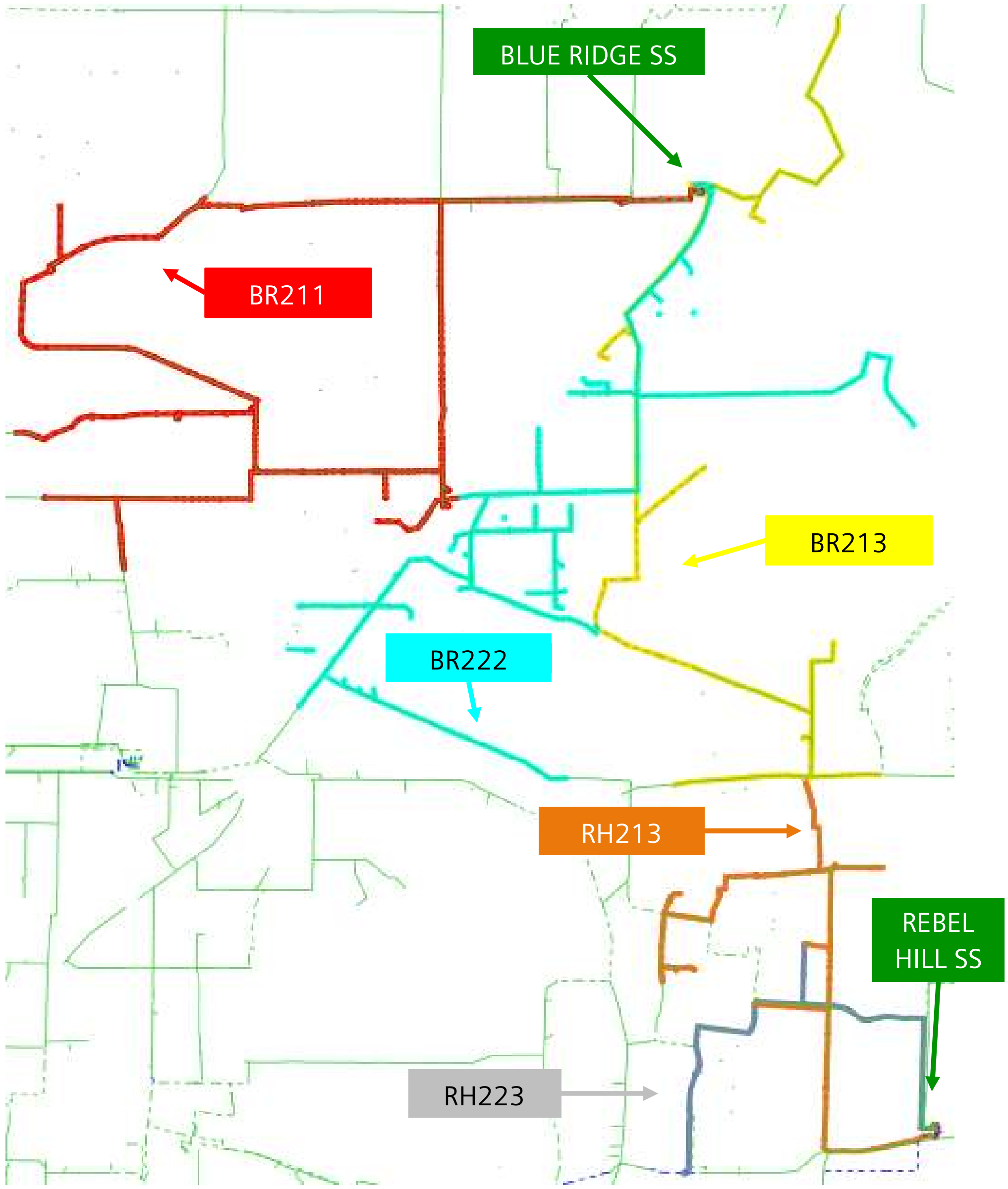


Figure 5-102 Supply area of associated feeders in Area 14

With the current configuration, the load at these feeders before any transfer is shown in Table 5-81.

Table 5-81: Feeder loads of Area 14 before any transfer or investment

Feeder	2020 P [MW]	2025 P [MW]	2030 P [MW]	2040 P [MW]
BR211	6.14	6.04	6.19	6.62
BR222	5.96	5.86	6.32	7.45
RH223	1.48	1.50	1.48	1.49
BR213	4.87	5.28	5.87	6.99
RH213	3.36	3.36	3.41	3.59

We understand that Blue Ridge has not enough space for an expansion with a third transformer in the future. However, the load growth in the supply area of Blue Ridge would result in Blue Ridge transformers to overload under emergency conditions. When one of the transformers at Blue Ridge is out of service, the other would be overloaded to 110.8% as shown in Table 5-82. Therefore, the main approach for the solutions was to transfer load from Blue Ridge to Rebel Hill which is proposed to have a new transformer in 2025.

Table 5-82: Violations under Power Plant transformer emergency condition in 2025

Substation	Substation Load [MVA]	Number of Transformer	Transformer Capacity [MVA]	N-1 Loading [%]	Appearance Year
Blue Ridge	25.4	2	22.9	110.8%	2025

RH213 and RH223 feeders are lightly loaded feeders, and these feeders are good candidates to transfer load from Blue Ridge to Rebel Hill. Therefore, a new section (Project 19, 500 kcmil CU – 0.799 mi) is proposed to extend RH223 to take some load from BR222. By extending RH223, it takes loads mainly from BR222 and some loads from BR213 and PP222 as well. RH213 has already connections with BR213. Some sections of BR213 can be transferred to RH213 by making only switching operations. Additional investments are not required for load transfer. With the supply area reconfiguration above, BR222 can be transferred to RH223 in each term without any loading or voltage violation and valid as vice versa; RN223 can be transferred to BR222. BR213 and RH213 have also same performance and can provide each other backup without voltage or loading violations.

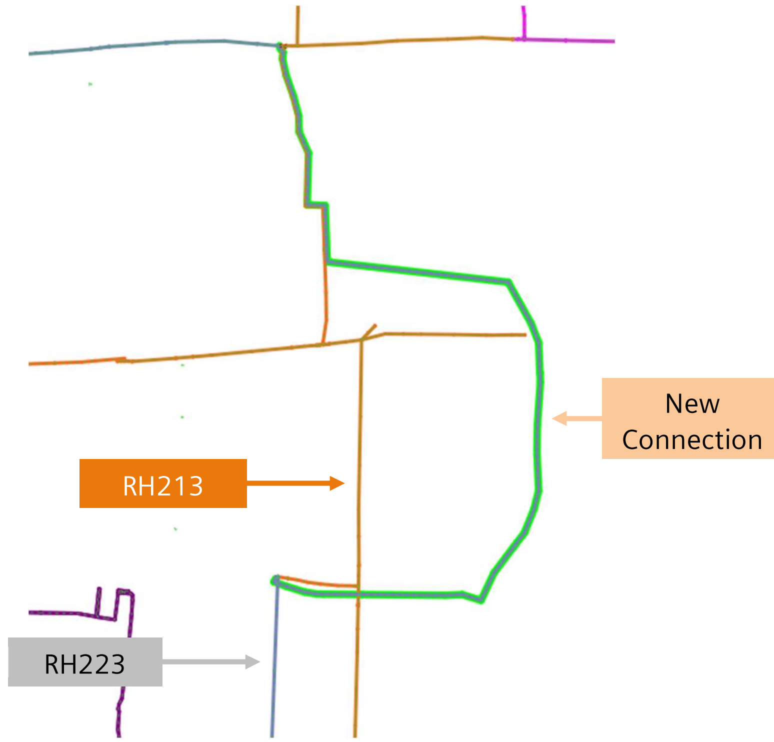


Figure 5-103 Project 19 - New section for RH223 extension

BR211 and BR222 feeder are adjacent feeders. BR211 can be transferred to BR222 in each term without any loading or voltage violation.

Reconfiguration of supply areas and related switching for Area 14 is illustrated in Figure 5-104. The new loads for the associated feeders are shown in Table 5-83.

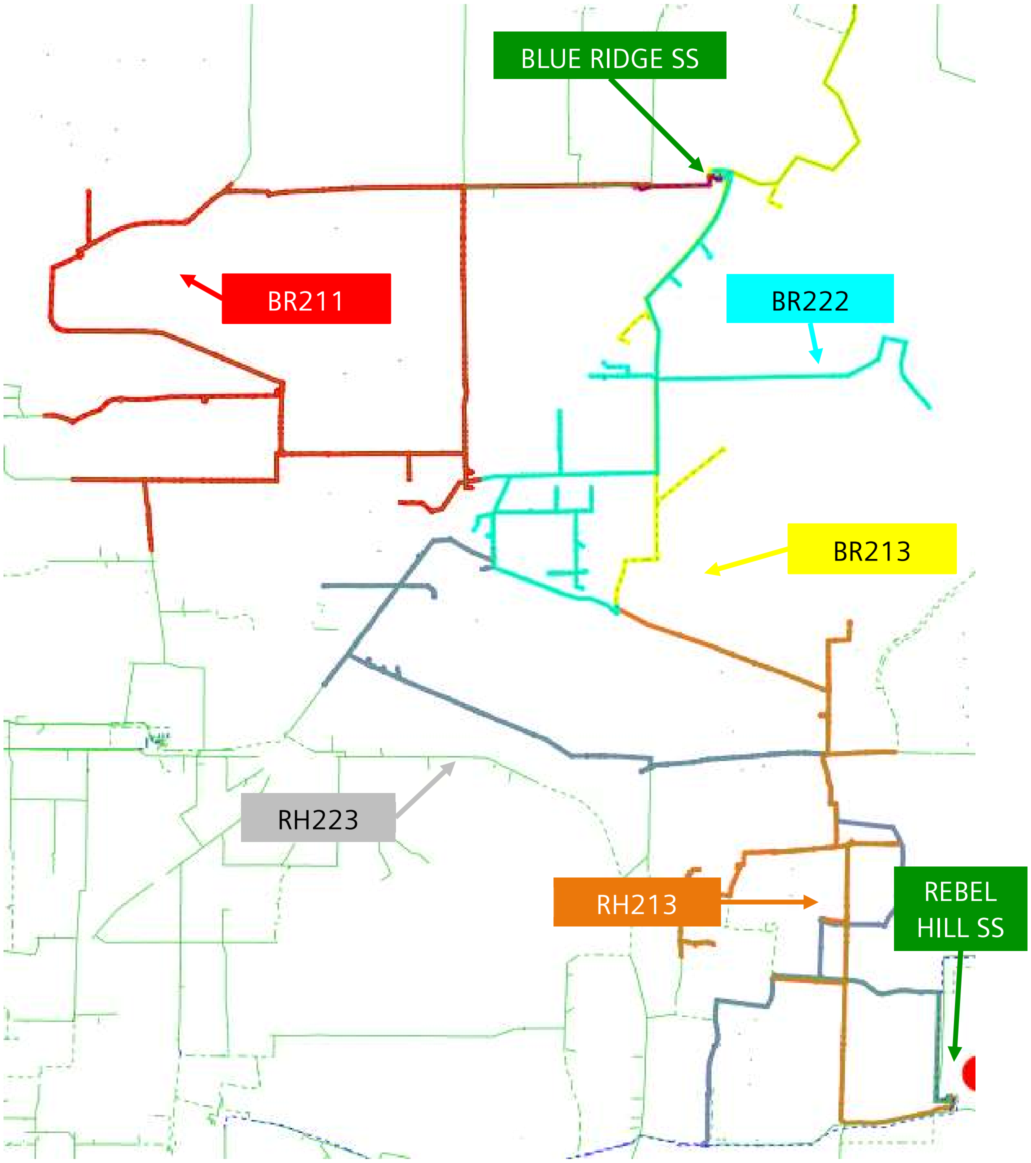


Figure 5-104 Proposed supply area for Area 14 in 2025

Table 5-83: Feeder loads of Area 14 after supply area reconfiguration

Feeder	2025 P [MW]	2030 P [MW]	2040 P [MW]
BR211	6.04	6.19	6.62
BR222	3.55	3.88	4.69
RH223	5.71	5.97	6.62
BR213	1.94	2.14	2.60
RH213	5.13	5.40	5.96

New capacitor banks are proposed to improve power factor at various locations. They are sized considering the preference to prevent injection of reactive power at the substation back to transmission. They are listed in Table 5-79 according to sizes and in service dates. Additionally, location of capacitor banks is shown in Figure 5-101.

Table 5-84: New capacitor banks for Area 13

Feeder Name	2025 300 kVAr	2025 600 kVAr	2025 1200 kVAr	2030 300 kVAr	2040 300 kVAr
BR211	-	-	-	-	-
BR222	-	-	-	-	-
RH223	1	2	-	1	1
BR213	-	-	1	-	1
RH213	-	1	-	-	1

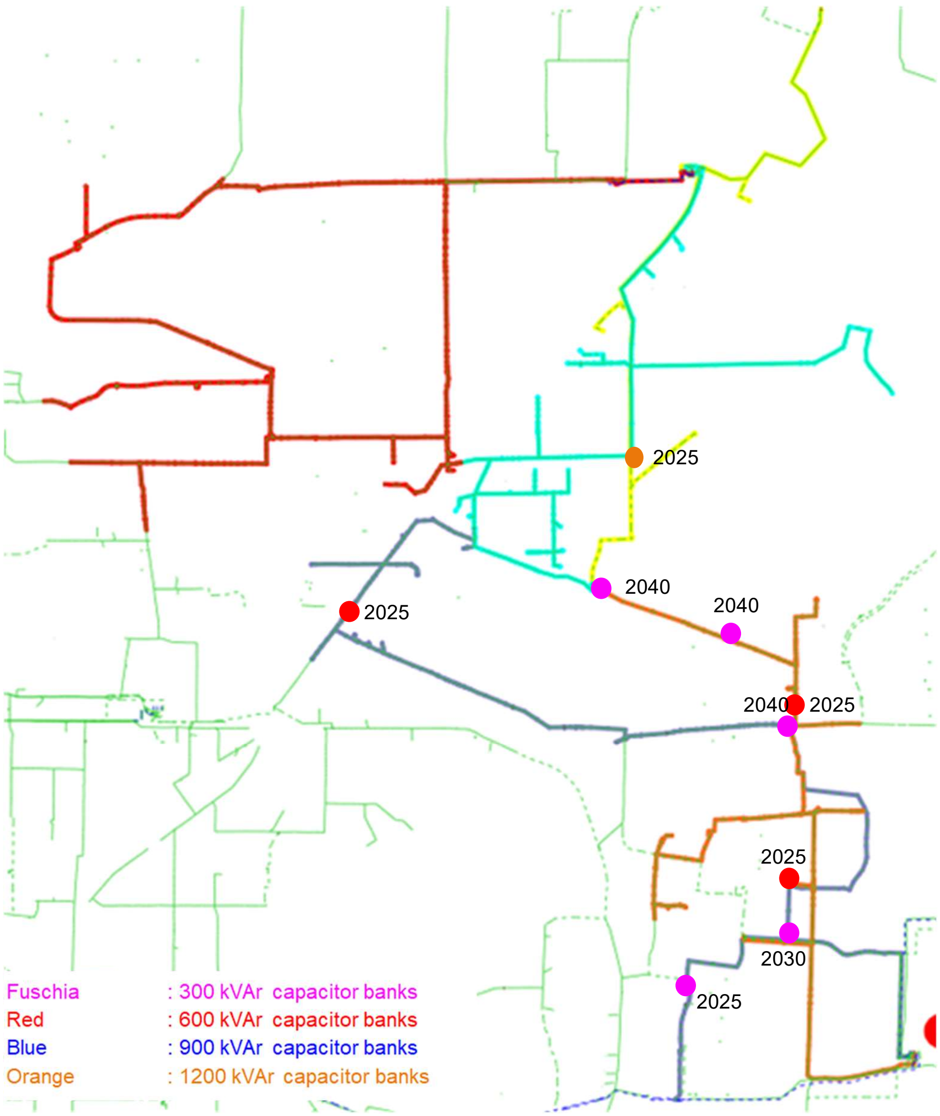


Figure 5-105 New capacitor banks in Area 14

The reinforced proposed system was analyzed under emergency conditions Table 5-85 summarizes for feeders BR211, BR213, BR222, RH213 and RH223what is the recommended backup feeder(s) for each term. These back up feeders can accept all load from main feeder (with the contingency) without loading or voltage violations.

Table 5-85: Back-up feeders of Area 14 for each term

Substation	Main Feeder	2025 Back-Up Feeder-1	2025 Back-Up Feeder-2	2030 Back-Up Feeder-1	2030 Back-Up Feeder-2	2040 Back-Up Feeder-1	2040 Back-Up Feeder-2
Blue Ridge	BR211	BR222	-	BR222	-	BR222	-
Blue Ridge	BR213	RH213	-	RH213	-	RH213	-
Blue Ridge	BR222	RH223	-	RH223	-	RH223	-
Rebel Hill	RH213	BR213	-	BR213	-	BR213	-
Rebel Hill	RH223	BR222	-	BR222	-	BR222	-

5.6 Future Distribution Network Performance.

In the prior sections the performance of the network under contingency was analyzed and reinforcements proposed. To complement that analysis in this section we present the entire system performance under normal or system intact conditions.

5.6.1 Future System analysis under 2025 Feeder Peak Load Conditions

There is no voltage violation under 2025 feeder peak load condition in future distribution network. The lowest voltage was detected at PC221 (99.4%) which also satisfies the minimum voltage defined in planning criteria. The network is colored with the same legend as described previously for voltage and loading evaluations. As shown in Figure 5-106, green color shows compliance to voltage limits defined in planning criteria.

As shown in Figure 5-107, there is no loading violation under 2025 feeder peak load conditions in future network. Loading of all lines was less than 100% of their rating (ampacity). Maximum line loading was 98.5% and appeared in the supply area of Bolstad Substation. This is due to small conductor size.

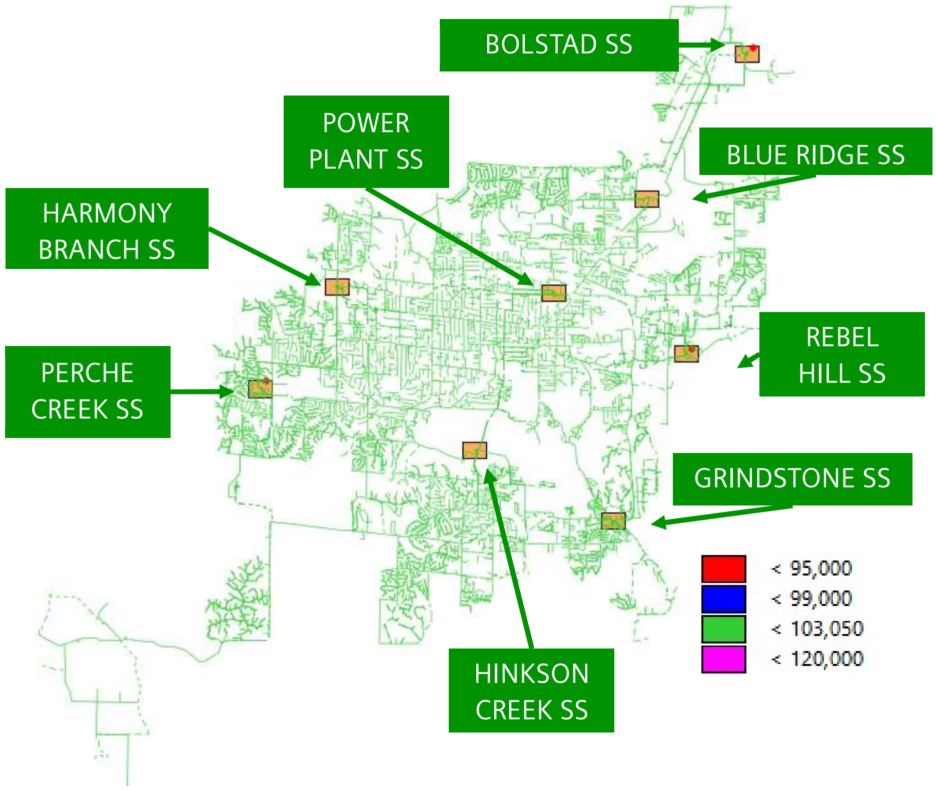


Figure 5-106 Voltage check in 2025 feeder peak load condition for future system

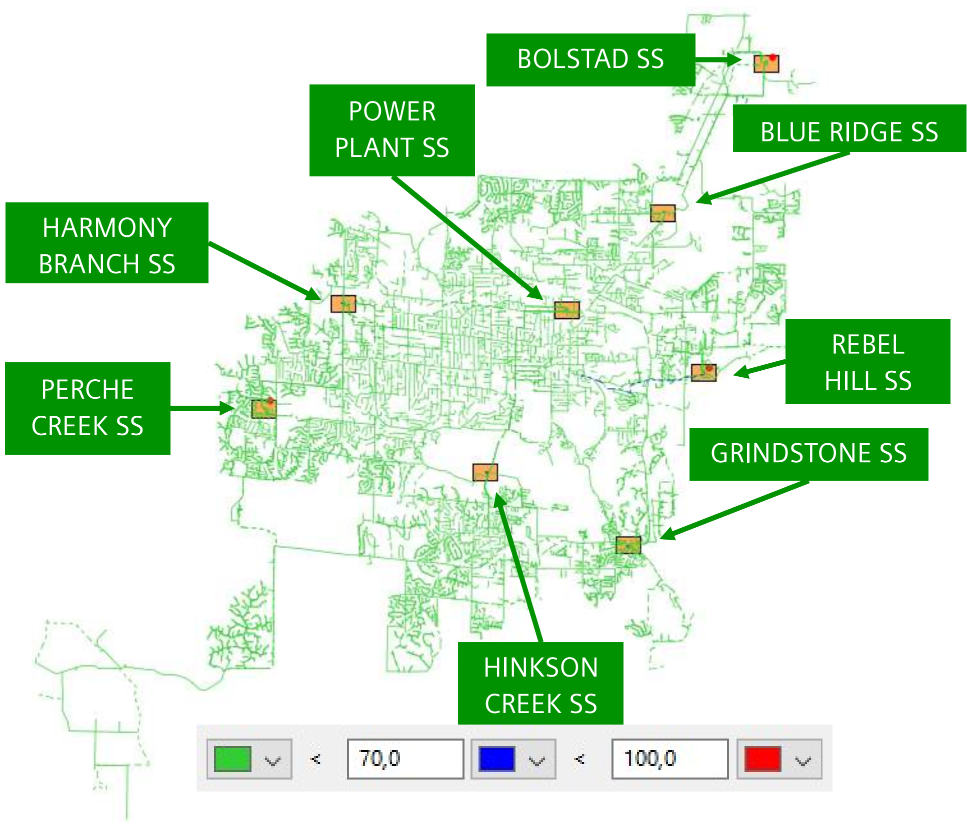


Figure 5-107 Loading check in 2025 feeder peak load condition for future system

5.6.2 Future System analysis under 2030 Feeder Peak Load Conditions

As is in 2025, there is no voltage violation under 2030 feeder peak load condition in future distribution network. The lowest voltage was detected at PC221 (99.5%) which also satisfies the minimum voltage defined in planning criteria. As shown in Figure 5-108, green color shows compliance to voltage limits defined in planning criteria.

Same as 2025 load condition, there is no loading violation under 2030 feeder peak load condition as shown in Figure 5-109. Maximum line loading was 79.7% in the supply area of Bolstad Substation due to small conductor size.

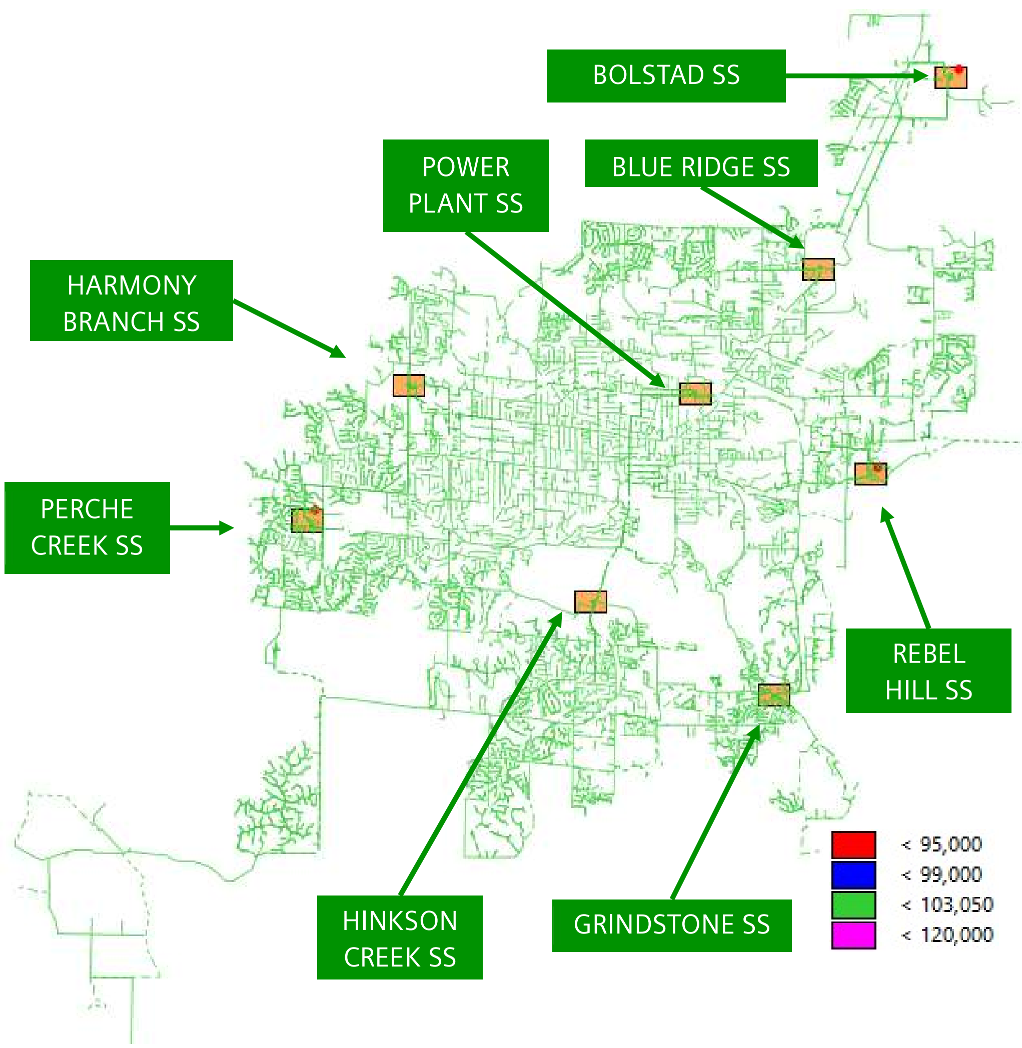


Figure 5-108 Voltage check in 2030 feeder peak load condition for future system

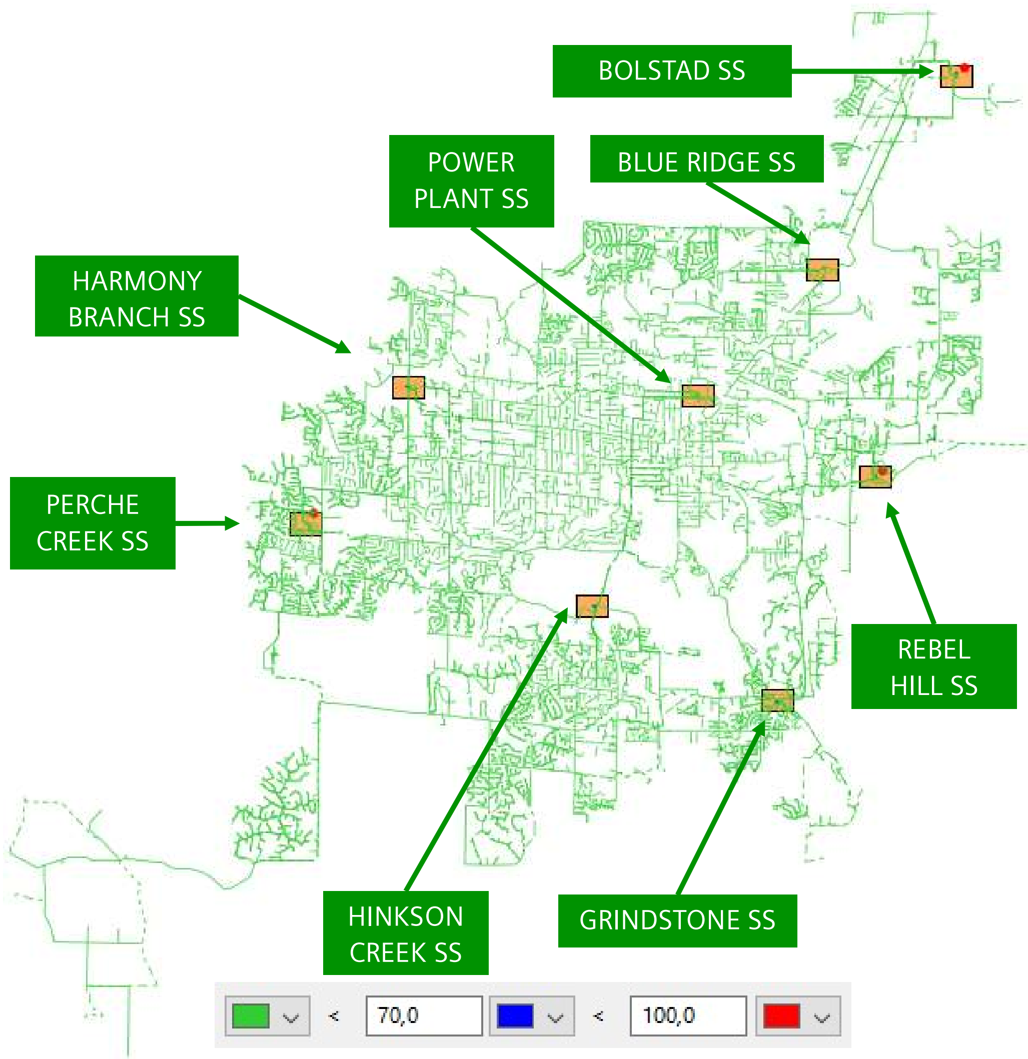


Figure 5-109 Loading check in 2030 feeder peak load condition for future system

5.6.3 Future System analysis under 2040 Feeder Peak Load Conditions

The situation is same as 2025 and 2030, feeder peak load conditions for 2040. The lowest voltage was detected at PC221 (99.3%) which also satisfies the minimum voltage defined in planning criteria. As shown in Figure 5-110, green color shows compliance to voltage limits defined in planning criteria.

Same as 2025 and 2030 load condition, there is no loading violation under 2040 feeder peak load condition as shown in Figure 5-111. Maximum line loading was 92.0% in the supply area of Bolstad Substation due to small conductor size.

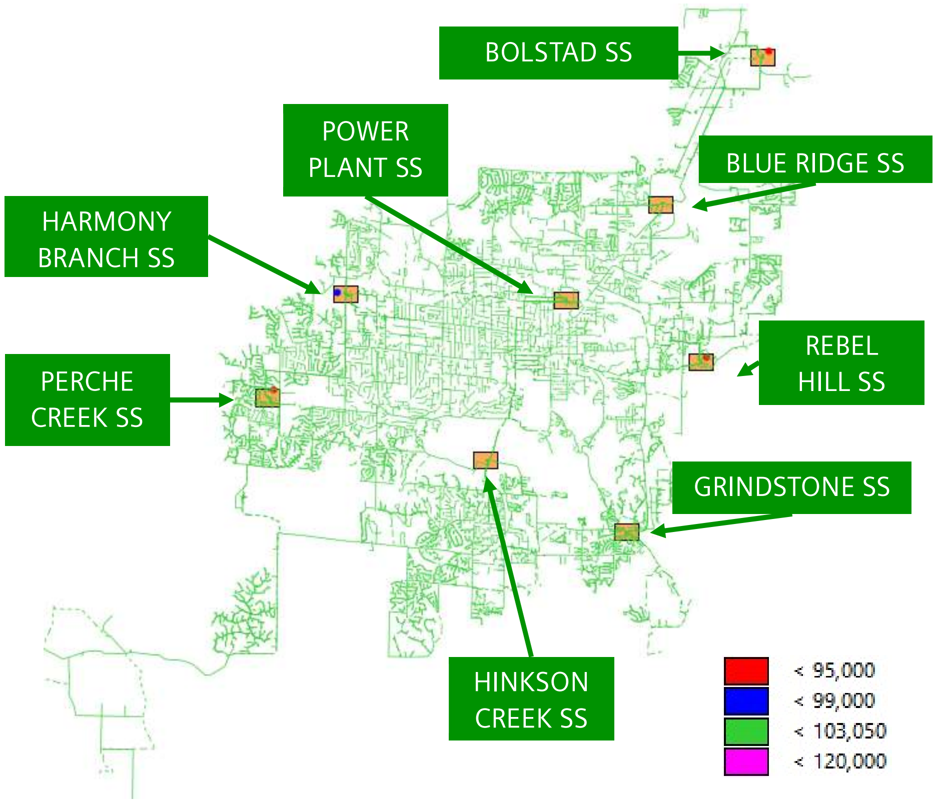


Figure 5-110 Voltage check in 2040 feeder peak load condition for future system

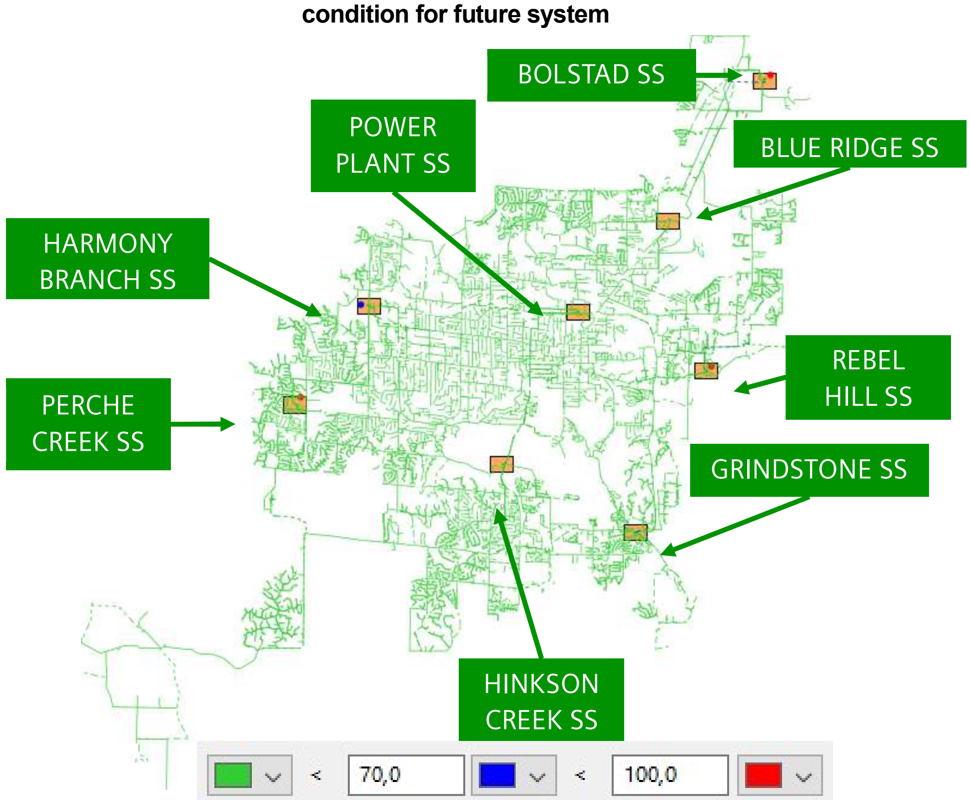


Figure 5-111 Loading check in 2040 feeder peak load condition for future system

5.7 Future Network Performance Under Minimum Load and High Distributed Generation Output Conditions

To complement the prior analysis CWL that was focused on individual feeder peak load conditions, in this section we review the operation when there is minimum system load at noon combined with maximum distributed generation output. Under this generation /load condition, there may be overvoltage issues, localized overloads, and potentially reverse power flow to transmission.

Reviewing the feeder head measurement, we identified that CWL distribution system had a minimum noon time system load condition of 100.55 MW recorded on 03/24/2019 12:00 pm. The daily load profile of each substation for that day (03/24/2019) is shown in Figure 5-112 and the demand of each feeder at that time was presented earlier in Table 5-3.

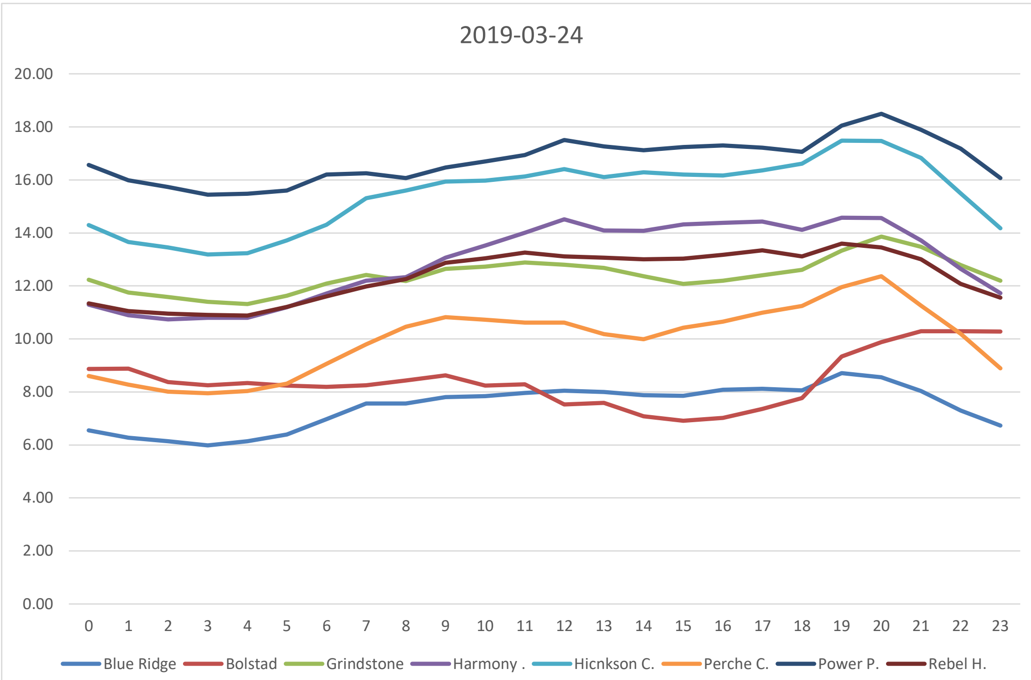


Figure 5-112 Load profile of each substation under minimum load condition

Distributed generation consists mainly of solar panels (PVs) and the values used in our study were derived from the generation forecast study and the allocation presented earlier in this report (Section 3). Table 5-86 shows the forecasted amounts of DGs for each term they were allocated to system considering the location and size of the load of the customers as discussed in Section 3. The resulting location is shown in Figure 5-113 below.

Table 5-86: Forecasted distributed generation between 2020 and 2040

	Residential MW	Commercial MW	Total MW
2020	1.73	1.78	3.5
2025	2.24	8.80	11.0
2030	3.62	41.38	45.0
2040	16.68	61.09	77.8

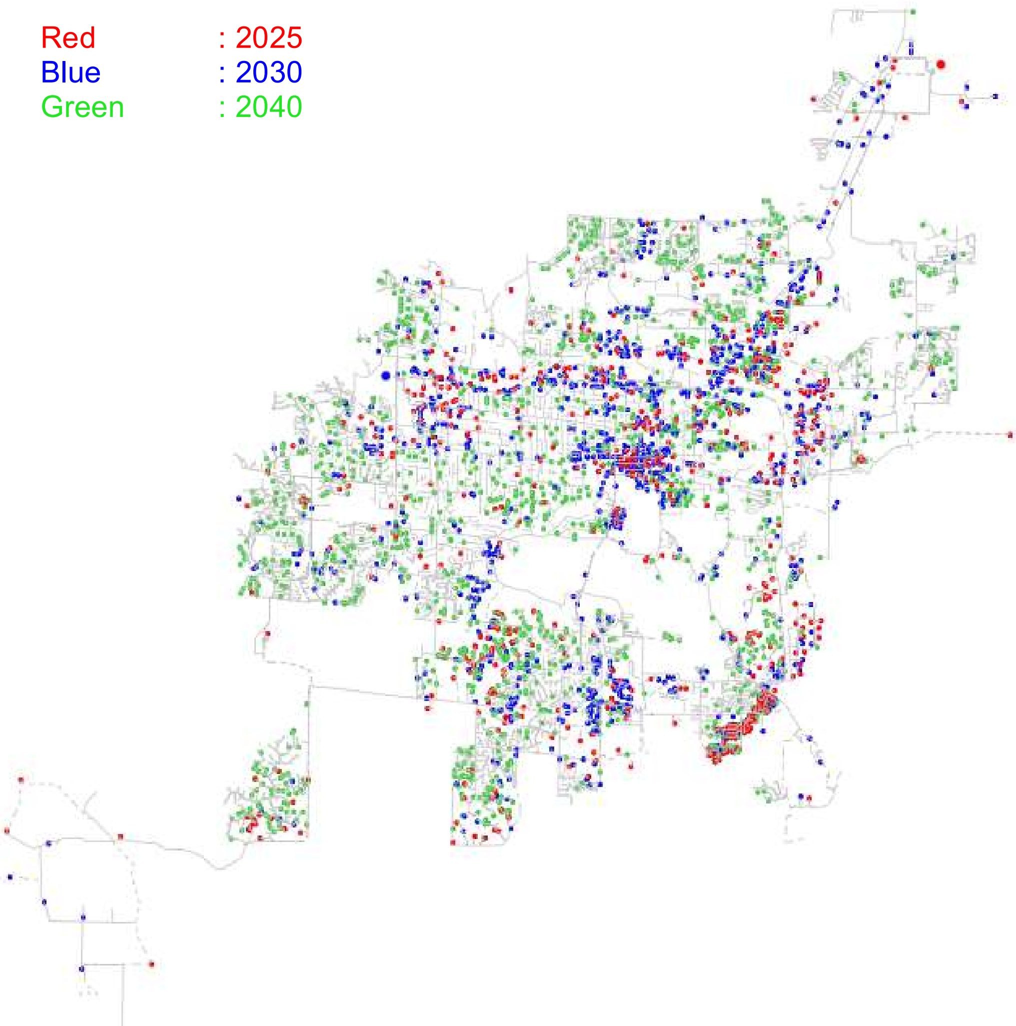


Figure 5-113: Location of forecast PVs between 2025 and 2040

Table 5-87 shows the forecasted levels of minimum system load and maximum distributed generation. As can be seen in Table 5-87, the highest DG penetration would be by 2040. Therefore, proposed CWL distribution system was analyzed under 2040 conditions initially to verify compliance with the planning criteria, an considering the final configuration recommended from the contingency analysis.

Table 5-87: Minimum system load and DG contribution for each term

Year	Min System Load [MW]	DG Contribution [MW]
2020	113.55	-
2025	115.36	11.04
2030	117.94	44.99
2040	128.78	77.76

Figure 5-114 shows the results of this analysis as a heat diagram. Nodes with the voltage less than 103% nominal that satisfies the planning criteria are colored green. Colors ranging from yellow to red indicate increasing levels of overvoltage violations and for 104.3% nominal and above the color is red.

As shown in Figure 5-114, there would be overvoltage violations around 104% especially near the water treatment facility and the residential area served by PC221. It is to be noted that this profile is without the possible NWA 3.5 MW PV that would make the situation worse, unless equipped with voltage control, as would be our recommendation.

In addition to the above, we observe overvoltages in the northwest of the system in the area largely supplied by BR212 out of Blue Ridge substation and PP233 out of Power Plant substation, south of Power Plant at the end of feeder GS232 out of Grindstone, RH231_ST out of Rebel Hill and HC233 out of Hinkson Creek substation and the area supplied by HB232 out of Harmony Branch and PC212 out of Perche Creek.

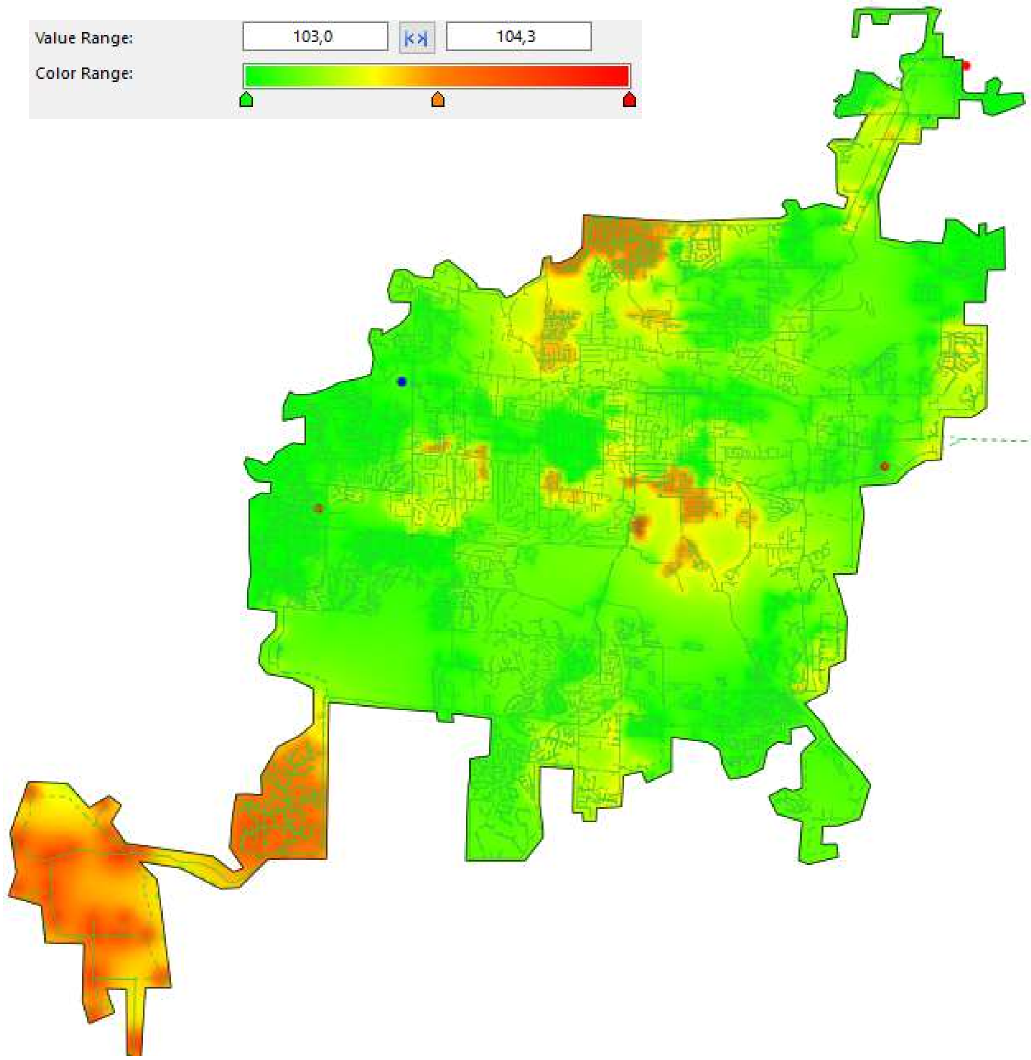


Figure 5-114 Voltage check under min. load and max. DG contribution by 2040 – 1.03 pu supply voltage

To address these overvoltages the first solutions considered were to adjust the power transformer taps to 1.0 pu from their normal 1.03 pu. This would likely have to be done on a daily basis or switching off capacitor banks along the feeder based on voltage.

When all transformer taps are moved to 1.0 pu, there would not be any overvoltage violation as shown in Figure 5-115 and as this solution is sufficient the switching off capacitor banks is not required in 2040.

We also noted that there is no reverse active power flow to transmission system as expected.

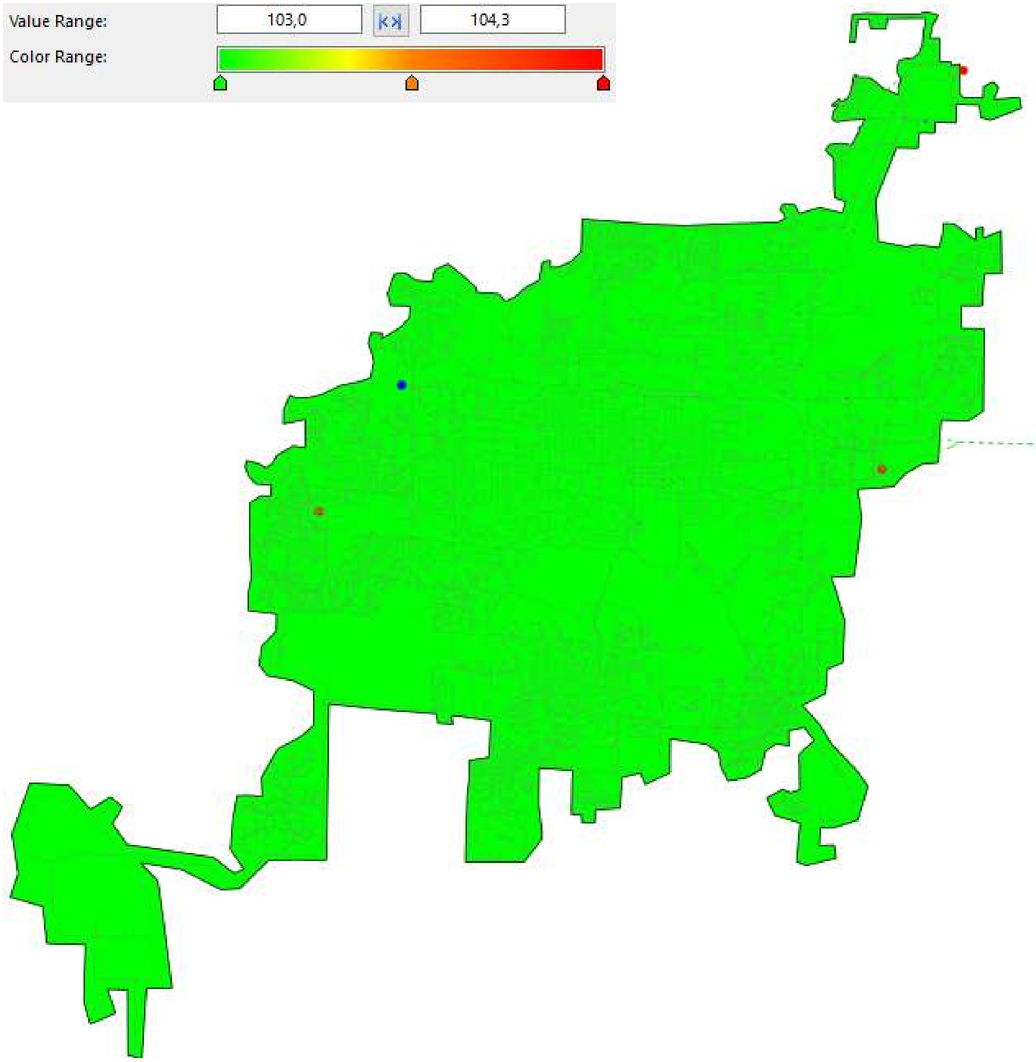


Figure 5-115 Voltage check under min. load and max. DG contribution by 2040 – 1.0 pu supply voltage

The distribution system was also analyzed under 2030 minimum system load and maximum DG contribution with the same configuration as proposed for 2030 from the contingency analysis. As shown in Figure 5-116, there would be overvoltage violations around 1.04 pu especially water treatment facility and residential area as well as the other areas experiencing overvoltages in 2040. In general, the overvoltages are less severe than with 2040 conditions.

When all transformer taps are moved to 1.0 pu, there would not be any overvoltage violation as shown in Figure 5-117 and no switching off capacitor banks is required in 2030. Also, there is no reverse active power flow to transmission system as expected.

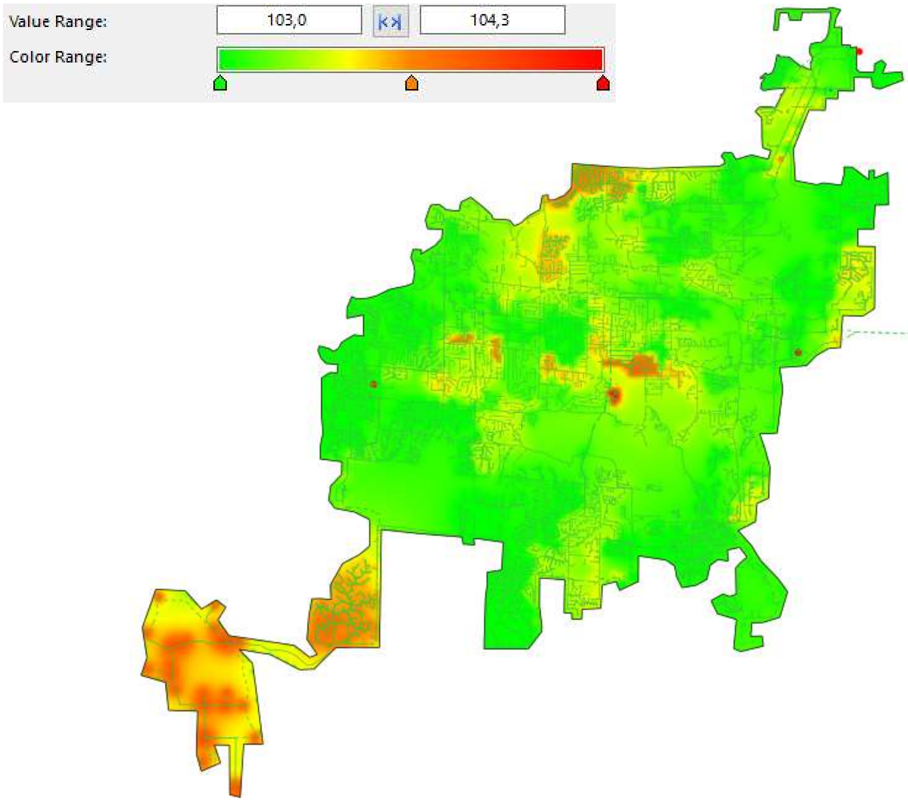


Figure 5-116 Voltage check under min. load and max. DG contribution by 2030 – 1.03 pu supply voltage

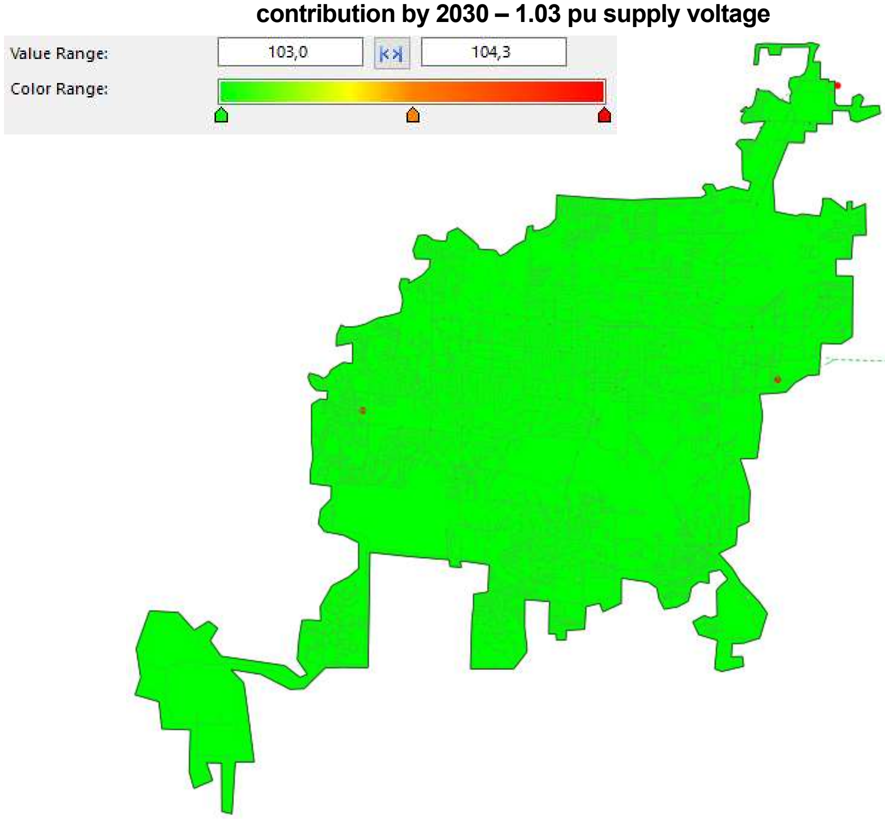


Figure 5-117 Voltage check under min. load and max. DG contribution by 2030 – 1.0 pu supply voltage

The distribution system is analyzed under 2025 minimum system load and maximum DG contribution with the same configuration as proposed for 2025 considering individual feeder peak load condition. As shown in Figure 5-118, there would be overvoltage violations around 1.04 pu especially water treatment facility and residential area close to there. Except that part, there would be still some overvoltage violations spread over the network but less than 2030 and 2040 conditions.

When all transformer taps are moved to 1.0 pu voltage level, there would not be any overvoltage violation as shown in Figure 5-119. Therefore, switching off capacitor banks is not required in 2025. Additionally, there is no reverse active power flow to transmission system as expected.

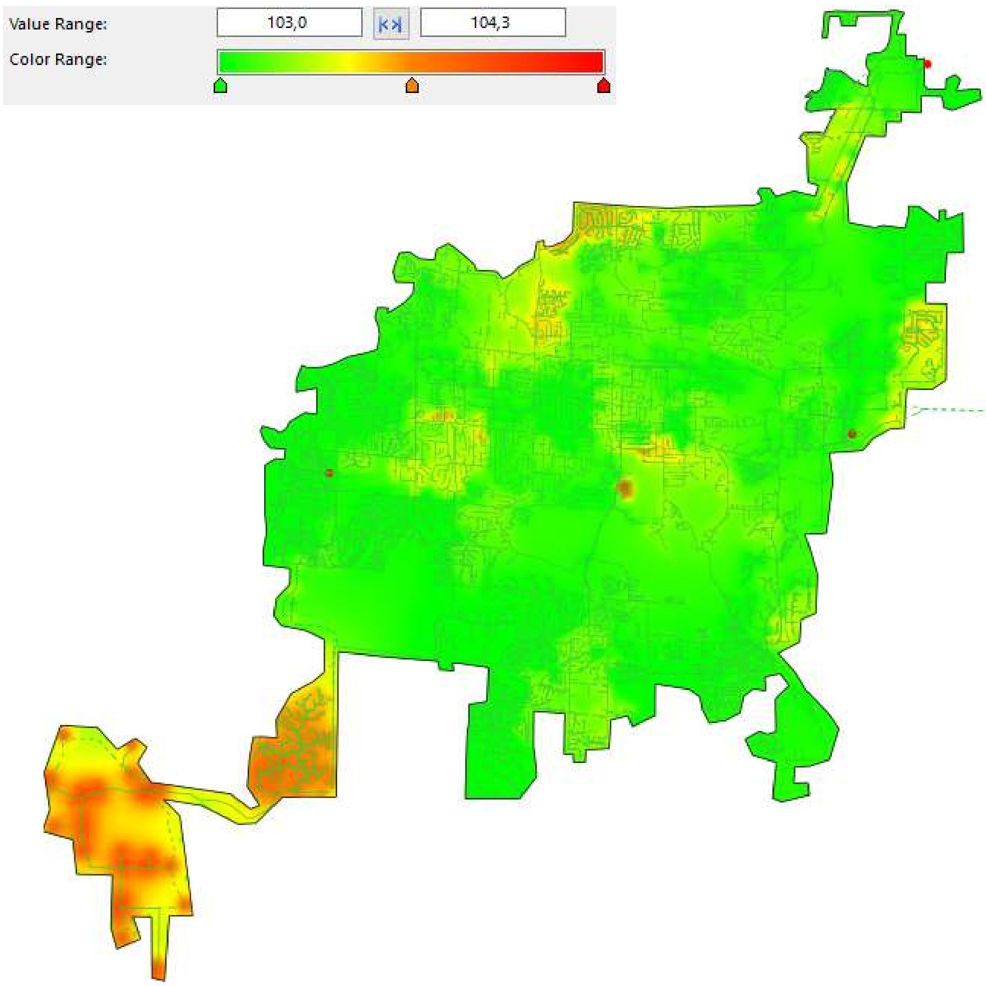


Figure 5-118 Voltage check under min. load and max. DG contribution by 2025 – 1.03 pu supply voltage

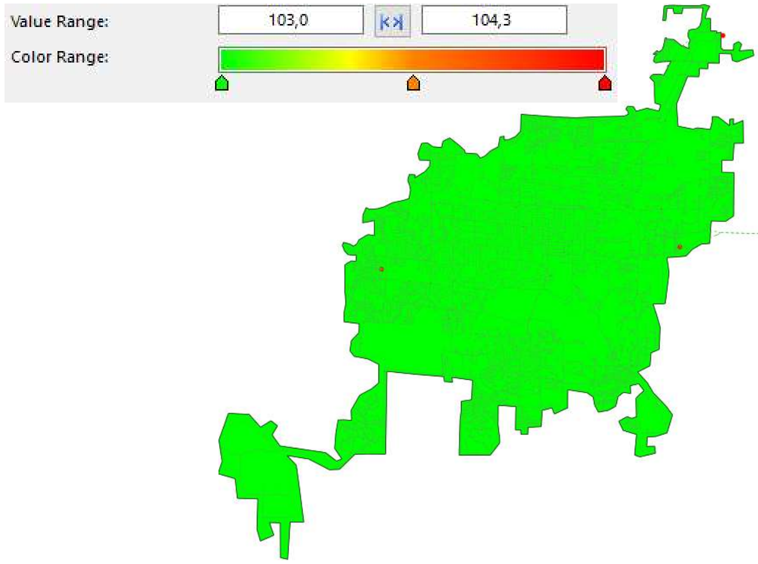


Figure 5-119 Voltage check under min. load and max. DG contribution by 2025 – 1.0 pu supply voltage

5.8 Substation Demands and Power Transformer Requirement in 2025, 2030 and 2040 Conditions

In Section 4 the substation transformer expansion needs, and coverage area of each substation was presented based on the spatial load forecast. This assessment and capacity expansion needs is further refined in this subsection considering the recommended investments presented above to address the loading under normal and contingency conditions of each feeder.

Figure 5-120 shows the final substation coverage area for the future network as determined from the normal and contingency loading of the feeders.

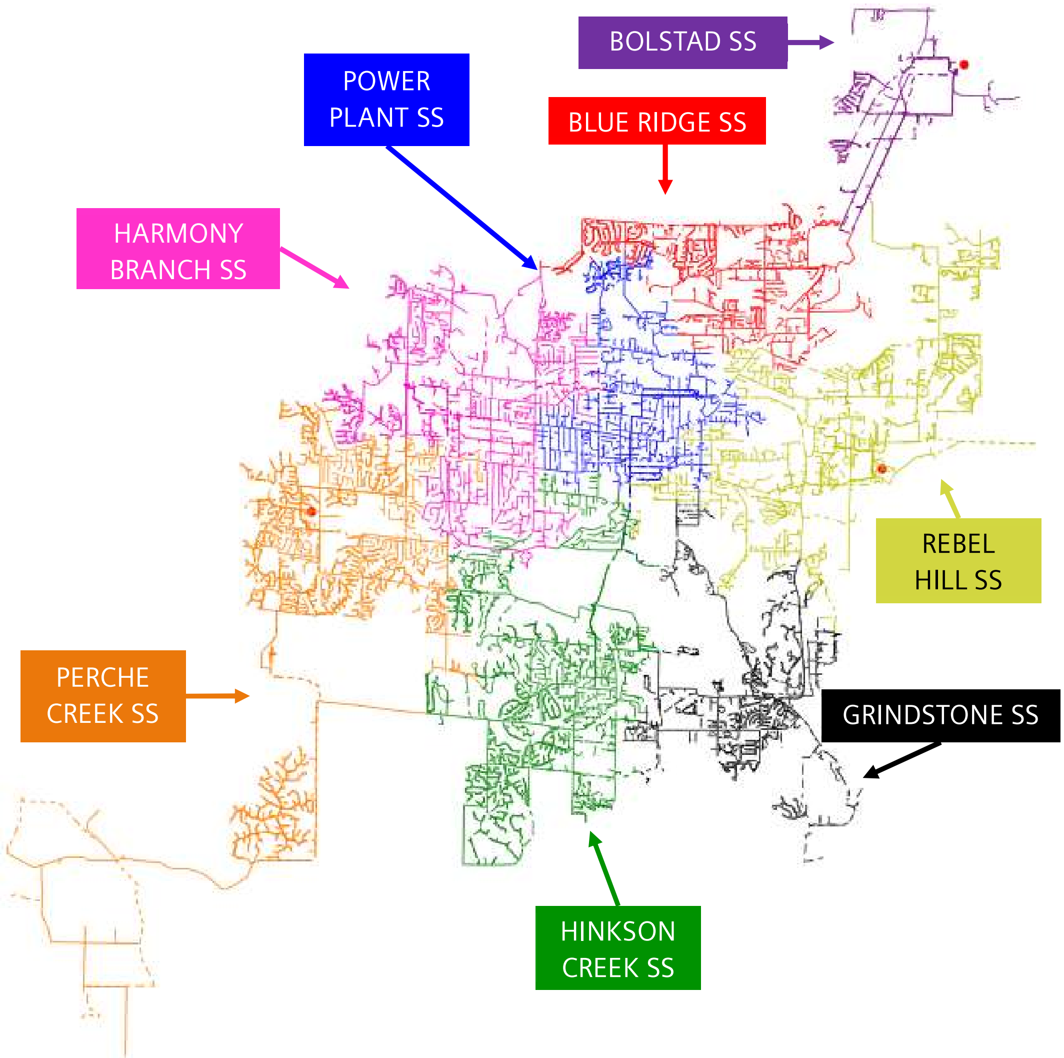


Figure 5-120 Substation coverage area of future network

The updated loading at each of the substations, considering the reconfiguration recommended, at the time of the system peak and at the time of the individual substation peak in MW is shown in Table 5-88. Note that the technical losses in the distribution system such as line and transformer losses are considered in these results and hence the total loading is slightly higher that the values reported in Section 4 subsection 4.3.

Table 5-88: Substation load for the future network by year

Substation	System Peak Load [MW]			Substation Peak Load [MW]		
	2025	2030	2040	2025	2030	2040
BLUE RIDGE	19.1	19.7	21.8	19.1	19.7	21.8
BOLSTAD	16.4	19.3	25.6	27.7	32.7	43.4
GRINDSTONE	32.9	33.8	37.1	39.3	40.4	44.4
HARMONY BRANCH	42.4	41.8	43.3	42.4	41.8	43.3
HINKSON CREEK	43.1	43.6	46.3	43.1	43.6	46.3
PERCHE CREEK	39.3	38.5	39.6	40.4	39.6	40.7
POWER PLANT	43.0	43.4	46.3	43.2	43.5	46.4
REBEL HILL	46.7	47.8	52.1	46.7	47.8	52.1
Total	**282.8**	**287.8**	**312.0**	**301.9**	**309.1**	**338.4**

An additional verification of the recommended substation coverage areas was carried out considering the load centers (a point that is load weighted equidistant to all loads served by the substation). Theoretically, the substation should be located as close as possible to load center of its coverage areas, thus minimizing feeders' losses, improving voltage profile, and improving the reliability by reducing the exposed line length.

Figure 5-121 shows the coverage area (with colored polyline), load center (with star) and spatial load density allocation (colored green to red) for each substation. As shown in Table 5-89, distances between substation and load centers in 2025 are acceptable based on our experience an no further load transfers are required. The distances for 2030 and 2040 are fundamentally the same as 2025 below.

Table 5-89: Distance between substation location and load centers in 2025

Substation	Distance Between SS Location and Load Center [mi]
BLUE RIDGE	0.86
BOLSTAD	0.85
GRINDSTONE	0.14
HARMONY BRANCH	0.79
HINKSON CREEK	0.69
PERCHE CREEK	0.55
POWER PLANT	0.77
REBEL HILL	0.96

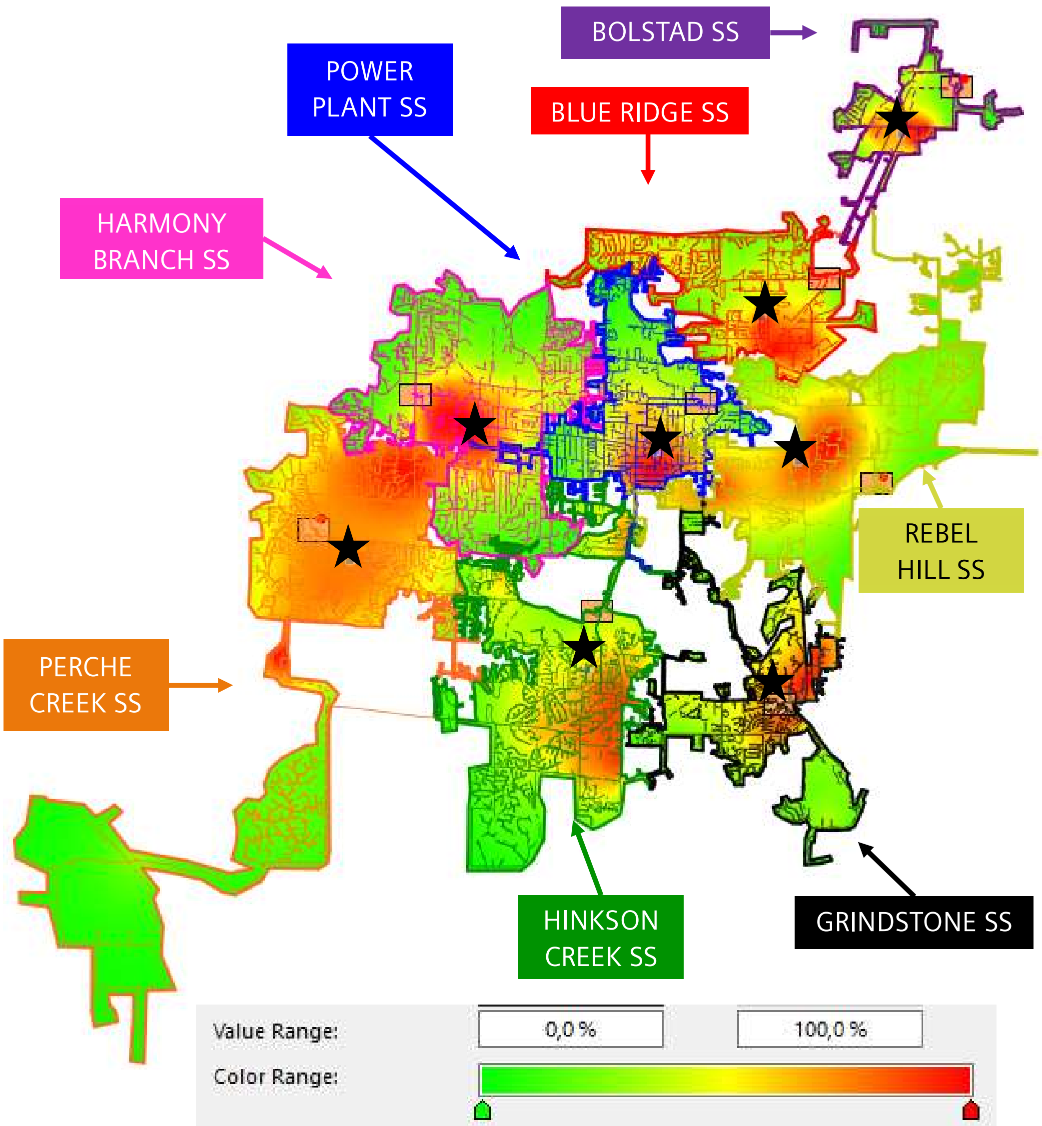


Figure 5-121 Load center of each substation in future network by 2025

As shown in Section 4, various substation installed transformers are expected to be overloaded under contingency conditions (n-1) and not be able to meet this criteria for the next 20 years. As shown in Section 4 additional transformers are required at Bolstad, Rebel Hill, Perche Creek by 2025 and Harmony Branch substations by 2040.

The detailed studies carried out in this section confirmed the new transformer requirements for Bolstad, Rebel Hill and Perche Creek by 2025. The main aim of new transformer at Harmony Branch substation by 2040 was to create capacity to take some load from adjacent substations, however the detailed feeder analysis identified other solutions and this transformer is no longer required.

The study identified that there would be a minor overloading at Power Plant and Hinkson Creek substation under emergency condition by 2040, but this issue can be solved by transferring a feeder to adjacent substations as detailed below.

Table 5-90 to Table 5-92 shows the peak substation load, the recommended installed transformation capacity, and the emergency (N-1) loading prior the recommended investments and after the investments. As can be observed all recommended transformers are expected to be necessary by 2025 to provide n-1 support.

Table 5-90: Peak Load, installed transformation capacity and emergency loading for each substation by 2025

Substation	Load [MVA]	Number of Transformer	Transformer Capacity [MVA]	Total Transformation Capacity [MVA]	Before Expansion N-1 Loading [%]	After Expansion N-1 Loading [%]	Note
BLUE RIDGE	19.1	2	22.4	44.8	85.0%	85.0%	
BOLSTAD	27.7	3	22.4	67.2	**123.8%**	61.9%	New 22.4 MVA Transformer
GRINDSTONE	39.3	3	22.4	67.2	87.8%	87.8%	
HARMONY BRANCH	42.4	3	22.4	67.2	94.6%	94.6%	
HINKSON CREEK	43.1	3	22.4	67.2	96.3%	96.3%	
PERCHE CREEK	40.4	3	22.4	67.2	**180.3%**	90.1%	New 22.4 MVA Transformer
POWER PLANT	43.2	3	22.4	67.2	96.3%	96.3%	
REBEL HILL	46.7	3	28.0	84.0	**166.7%**	83.4%	New 28 MVA Transformer

Table 5-91: Peak Load, installed transformation capacity and emergency loading for each substation by 2030

Substation	Load [MVA]	Number of Transformer	Transformer Capacity [MVA]	Total Transformation Capacity [MVA]	Before Expansion N-1 Loading [%]	After Expansion N-1 Loading [%]	Note
BLUE RIDGE	19.7	2	22.4	44.8	87.9%	87.9%	
BOLSTAD	32.7	3	22.4	67.2	**146.1%**	73.0%	New transformer in 2025
GRINDSTONE	40.4	3	22.4	67.2	90.1%	90.1%	
HARMONY BRANCH	41.8	3	22.4	67.2	93.4%	93.4%	
HINKSON CREEK	43.6	3	22.4	67.2	97.3%	97.3%	
PERCHE CREEK	39.6	3	22.4	67.2	**176.7%**	88.4%	New transformer in 2025
POWER PLANT	43.5	3	22.4	67.2	97.1%	97.1%	
REBEL HILL	47.8	3	28.0	84.0	**170.7%**	85.3%	New transformer in 2025

Table 5-92: Peak Load, installed transformation capacity and emergency loading for each substation by 2040

Substation	Load [MVA]	Number of Transformer	Transformer Capacity [MVA]	Total Transformation Capacity [MVA]	Before Expansion N-1 Loading [%]	After Expansion N-1 Loading [%]	Note
BLUE RIDGE	21.8	2	22.4	44.8	97.5%	97.5%	
BOLSTAD	43.4	3	22.4	67.2	**194.0%**	97.0%	New transformer in 2025
GRINDSTONE	44.4	3	22.4	67.2	99.0%	99.0%	
HARMONY BRANCH	43.3	3	22.4	67.2	96.6%	96.6%	
HINKSON CREEK	46.3	3	22.4	67.2	**103.4%**	**103.4%**	Address by load transferring
PERCHE CREEK	40.7	3	22.4	67.2	**181.7%**	90.8%	New transformer in 2025
POWER PLANT	46.4	3	22.4	67.2	**103.5%**	**103.5%**	Address by load transferring
REBEL HILL	52.1	3	28.0	84.0	**186.0%**	93.0%	New transformer in 2025

We also note that without any investments, the transformers in Hinkson Creek and Power Plant substations are projected to have minor overloads under emergency condition by 2040. However, these overloads can be mitigated by a single feeder transfer to adjacent substations. The candidate feeders to be transferred are listed below as they have adjacent feeders from other substations.

- For Hinkson Creek : HC213, HC221, HC231, HC232 and HC233
- For Power Plant : PP212, PP213, PP222 and PP231

5.9 Recommendation and Conclusions

Based on the results presented in this section it is possible to conclude that CWL distribution system is not expected to experience overloads or significant voltage violations during peak load and normal operating conditions (system intact) over the short term (2025) and only slight overloads at one Blue Ridge substation feeder exit (feeder BR222) by 2030. Over the long term (2040) various substation feeder exits in addition to Blue Ridge; Grindstone, Hinkson Creek, Rebel Hill and Bolstad would overload if no investments are made on the system. Low voltage performance violations are concentrated at the water treatment plant area, but these are not critical (above 0.95 pu).

Under emergency conditions, which assess the ability of a feeder to provide backup to an adjacent feeder and supply its load in case of an outage, several limitations were identified during peak load, and investments proposed to address them. These investments also address the normal operating condition overloads identified in the medium (2030) and long term (2040).

The investments we grouped in 20 distinct projects and most of them consist of changing the conductor on short feeder sections or adding a short new feeder section to allow interconnection and load transfers between feeders. The largest investments are associated with Perche Creek, Rebel Hill and Bolstad and are detailed next.

The largest investment is a new feeder out of Perche Creek to provide backup to the Wastewater processing facility and extending to the residential area South of Perche Creek to provide backup that this load currently lacks. This is identified as Project 11 and an alternative using PV and Batteries was proposed to provide backup in lieu of the feeder extension to the residential area. Additionally, a new feeder (Project 8) is proposed for Perche Creek, but the investments are largely inside the substation as this new feeder has a short section connecting to the existing PC223 that is partially transferred to the new feeder

The second largest investments are associated with Rebel Hill and include two new feeders to alleviate overloads during emergency conditions (Project 17) and support the load transfers from Grindstone (Project 20). Additionally, there is a need for a longer feeder section (Project 19) to transfer load from Blue Ridge to Rebel Hill. These investments add flexibility to the network by stablishing new connections and NWA would not be good substitute as, unlike the case of the residential area above, there are no loads that can be easily isolated.

In addition to the above a new feeder (Project 4) is proposed out of Bolstad to be implemented together with the new transformer to address both normal and emergency conditions overloads. The balance of these investments is small and include capacitor banks for power factor correction and voltage support.

With the investments recommended in this section 5 the system is projected to have adequate performance under the short, medium, and long term and the analysis under light load and high distributed generation dispatch, also showed that no additional investments would be necessary, beyond adjusting the taps of the transformers at the substations. Finally, this section confirms the need to expand the transformation capacity at Perche Creek, Bolstad and Rebel Hill by 2025 but not at Harmony Branch even in the long term.

6 Transmission System Assessment

6.1 Introduction

This chapter presents the transmission analysis of City of Columbia transmission system. In this study, the impact of load growth obtained from the Spatial Load Forecast and the proposed Integrated Resource Plan on CWL's transmission system is assessed, namely the impact of adding the 64 MW Boone Stephens Photovoltaic facility at Bolstad substation and the impact of building locally a photovoltaic (PV) facility plus storage as a non-wire-alternative (NWA) to reliability issues identified. The analysis also includes the evaluation of observed stresses in the system due to the occurrence of throughflows combined with multiple outages as observed in April 2020 and the impact of a Firm Transmission Request from University of Missouri, Columbia (UMC). Solutions to reliability issues are presented to ensure compliance with NERC planning requirements.

Due to Critical Energy Infrastructure Considerations this section was redacted in this version of the report

6.2 Overview of CWL Transmission System

CWL system is in the seams between Ameren Missouri (AMMO) in MISO and AECI, which makes it subject to throughflows between these entities as analyzed later in this report.

[redacted]

6.3 Study Process

CWL transmission system was studied by conducting steady state contingency analysis for the Summer Peak Load and Spring Light Load cases for the three study years 2020, 2025 and 2030.

Contingency analysis is a "what if" scenario simulator that evaluates the impacts on CWL's electric power system when problems occur. In this analysis current and future conditions are modeled for various load levels and generation dispatches, outage of single or multiple elements in CWL and surrounding transmission system are simulated and their impacts on CWL's transmission system are evaluated. The following impacts are noted during this analysis:

- **Thermal Violation:** Power flowing on a transmission line or transformer that exceeds its rating.
- **Voltage Violation:** at a transmission bus is outside limits specified in planning standards (under 95% or above 105% nominal for normal

conditions and under 90% or above 105% nominal for contingency conditions)

Finally, a mitigation and/or system reinforcements are identified.

The simulated outages are categorized based on NERC category and planning criteria (TPL-001-4). The types of the simulated outages are as follow:

- **Single element out:** this is the most common type of outage, and the system must be prepared to withstand it without any voltage or thermal (loading) violations (P1 and P2 NERC Categories).
- **Generator out and another element:** this is also common as generators can be out for many reasons including economics and the same criteria above applies (P3 NERC Category).
- **Protection Failure:** leading to multiple elements out, it is rare, could be avoided by duplicating the protection and in systems under 300 kV some load shed is allowed (P5 NERC Category).
- **Two overlapping contingencies:** typically, one element in maintenance (scheduled or forced because of a fault), following by a trip of another element. It is rare for this type of events to happen at peak load and some load shedding is allowed (P6 NERC Category). Most of the overloads presented in this study fall under this category.
- **Common tower outage:** two or more circuits that share the same structure and sometimes same right of way are outaged simultaneously. Some load shedding is allowed.

Table 5-1 provides an overview of the planning criteria (TPL-001-4). The shading indicates whether the type of outage created an overload in any of the cases analyzed.

Table 6-1: Types of simulated outages

Contingency Category	Initial Conditions	Outage Event	Interruption of Firm Transmission Service Allowed	Non-Consequential Load Loss Allowed
No Contingency (P0)	Normal System	No Outage	No	No
Single Contingency (P1)	Normal System	Loss of generator, transmission line or transformer	No	No
Failure at Substation (P2)	Normal System	1. Bus Section Outage 2. Internal Breaker Fault	Yes, in most cases (V<300 kV)	Yes, in most cases (V<300 kV)
Prior Generation Outage (P3)	Loss of generator unit followed by System adjustments	Loss of generator, transmission line or transformer	No	No
Stuck Breaker Contingency (P4)	Normal System	Loss of multiple elements caused by a stuck breaker attempting to clear a fault on a transmission element	Yes	Yes

Contingency Category	Initial Conditions	Outage Event	Interruption of Firm Transmission Service Allowed	Non-Consequential Load Loss Allowed
Protection failure Contingency (P5)	Normal System	Failure of a non-redundant relay protecting the faulted element to operate as designed, for a generation, transmission line, transformer, bus section; multiple elements out	Yes	Yes
Two overlapping Singles Contingency (P6)	Loss of a transmission line or transformer followed by system adjustments	Loss of generator, transmission line or transformer, typically during maintenance of the first element.	Yes	Yes
Common Structure Contingency (P7)	Normal System	Loss of any two transmission lines on common structure	Yes	Yes

6.4 Study Assumptions

This study was conducted using the Summer Peak Load and Spring Light Load cases for the three study years 2020, 2025 and 2030. The Summer Peak represent the maximum stresses in the CWL system, and the Spring Light Load evaluates the impacts of throughflows on CWL system with selected maintenance outages.

The summer peak load cases were modeled using the following MISO cases:

- 2020 Summer Peak: MISO19_2021_SUM___TA_Final.sav
- 2025 Summer Peak: MISO19_2024_SUM___TA_Final.sav
- 2030 Summer Peak MISO19_2029_SUM___TA_Final.sav

Cases were adjusted as follows:

- CWL loads are based on spatial load forecast for years (2020, 2025 and 2030, respectively).
- The 64 MW Boone Stephens PV facility at Bolstad was dispatched at its max in 2025 and 2030 cases.
- 10 MW Truman PV facility was modeled by reducing loads at Rebel Hill in 2025 and 2030 cases. This facility is connected at the distribution level.
- [redacted].

The spring light load cases were modeled using the following MISO cases:

- 2020 Shoulder Case: MISO19_2020_SH90__TA_Final.sav
- 2025 Shoulder Case: MISO19_2024_SH90__TA_Final.sav
- 2030 Shoulder Case: MISO19_2029_SH40__TA_Final.sav

Cases were adjusted as follows:

- CWL loads are scaled to represent light load based on ratios of spatial load forecast for years (2020, 2025 and 2030, respectively).
- 64 MW Boone Stephens PV facility at Bolstad substation is dispatched at 50% of its max in 2025 and 2030 cases

- 5 MW Truman PV facility (50% of max) is modeled by reducing loads at Rebel Hill in 2025 and 2030 cases.
- [redacted].

6.5 Summer Peak Load Scenario

The summer case highlighted some of the known vulnerabilities in the system. These vulnerabilities can be segregated into vulnerabilities in the adjacent systems, which are not directly impacted by CWL load but can be influenced by the dispatch of CWL generation and CWL system vulnerabilities.

6.5.1 Vulnerabilities in adjacent systems (AMMO and AECI)

[Redacted]

6.5.2 Vulnerabilities in CWL system

[Redacted]

6.6 Assessment of Mitigation Options.

[Redacted]

6.7 Non Wires Solutions for N-1-1 overloads identified in CWL system under Summer Peak Conditions.

6.7.1 Solution Design.

CWL has identified various transmission solutions that would address the vulnerability discussed above. These solutions largely reinforce Perche Creek by adding a second supply point at 161 kV and are the subject of a separate study. However, under this study an alternative non wires solution was investigated. This solution consists in providing a second supply point to Perche Creek by a combination of solar PV and battery energy storage.

[Redacted]

6.7.2 Verification of effectiveness

[redacted]

6.8 Spring Light Load Scenario

[Redacted]

6.9 Impact of Boone Stephens 64 MW PV

This study assessed the addition of 64 MW of the Boone Stephens PV project at Bolstad. The CEC generation, that also connects to the same substation, was also dispatched in the case at maximum output (134 MW). The generation at Power Plant was also placed in-service to create a stressed case.
[Redacted]

6.10 Impact of a potential UMC Firm Capacity Request

This sensitivity analysis was conducted to assess the impact of a 40 MW UMC Firm transmission capacity request in the 2030 time frame. This analysis was evaluated for both summer peak load and light load scenarios under single (P1 NERC category) and multiple (P2, P4, P5, P7 NERC categories) and also under N-1-1 contingencies (P3 and P6 NERC categories).

[redacted]

6.11 Conclusion and Recommendations

Based on the studies presented in this section of the report we conclude that CWL transmission system is expected to perform adequately and within NERC standards without the need of any major investments in the network, beyond those already defined.

[redacted]

7 Standards Review

7.1 Introduction

Advisian, as part of the Siemens team, was engaged by Columbia Water and Light (CWL) to help revise and codify their existing engineering standards. In the face of a changing industry landscape and ageing workforce, the municipal utility is presented with the challenge of ensuring that the valuable lessons learned from both other utilities and their staffs' experience within their service territory are recorded and preserved. The expanding footprint of distributed energy resources (DER) such as solar PV and the integration of battery energy storage on distribution networks has the potential to disrupt network operations if not interconnected properly. Similarly, there are aspects of Columbia, MO that are unique to its geography such that the integration of new projects, performing of repairs, or upgrades to the network need to be handled in a specific manner – lessons that have been learned by CWL's staff over the years.

The purpose of this section is to provide a high-level view of the engineering standards typically employed at a mid-size distribution utility. The following pages will present engineering standards based on asset category, provide a brief description of the objective of the standard, detail some of the nationally recognized technical standards applicable to the area, and offer an overview of the types of information that would typically be included in such a standard in the form of a sample Table of Contents. Typically, many of these standards would be written specifically applicable to residential or commercial and Industrial customers, or may be sectioned based on voltage levels, capacity, etc. However, to eliminate redundancy, the standards have been consolidated at asset types as opposed to other sizing metrics.

The asset categories contemplated in this section include:

- General
- Distribution Lines
- Plug-In Electric Vehicle Interconnection
- Substations
- Inverter Interconnected Assets
- Metering Equipment
- Control and Monitoring Systems
- Civil / Structural Design Standards

7.2 Standard Application

For each standard, CWL will need to develop several policies and procedures for items such as how and when the standard is applied, what levels of approvals and sign-off should occur when work is performed, and what levels of approval will be necessary to make changes in the standard. Policies and procedures can also cover the method and documentation required for a new project; for example, how a basis for design for a project is presented, what is included in preliminary design vs. 30% / 60% / 90%, how design details are confirmed against approved standards and drawings. Similarly, CWL will need to develop a document retention and review policy to ensure the most up-to-date standards are available to the staff who need access. It is also important to note that the development of engineering standards does not replace the experienced engineering judgement of a registered professional engineer.

7.3 Methodology

In developing this section of the report, Advisian performed open-source searches of both similar sized utilities as well as large IOUs to identify a wide range of available engineering standards. Using these standards and our conversations with CWL staff the team created asset categories that were most applicable to CWL. The team then interviewed internal subject matter experts and cross referenced these categories with existing national standards bodies such as IEEE, ANSI, IEC, and others. Finally, the team inspected the representative engineering standard examples to identify and catalogue the categories of information most often included in engineering standards at other utilities.

It should be noted that CWL has an excellent set of standard engineering drawings that cover overhead distribution lines, pole mounted equipment such as transformers, some pad mounted equipment such as transformers and switchgears, and some metering and distribution panel types. In assessing which new standards need to be developed, including these existing drawings into the relevant new standard was an integral part of our planned approach.

7.4 General

7.4.1 Objective of the Standard

This standard captures some overarching standards that apply across multiple asset categories (i.e., safety codes) and others that are important put do not fit well under a specific asset category.

7.4.2 Sample of Applicable National Standards

- Building codes
- IEEE C2 National Electrical Safety Code

7.4.3 Sample of Table of Contents Headers

- Minimum Safe Working Distances: items such as: minimum distances for working near lines, minimum distances for scaffolding, booms, tools, structures, equipment
- Safety rules for installation and maintenance of overhead power lines
- Safety rules for installation and maintenance of underground power lines
- Work rules for the operation of power lines

7.5 Low Voltage Distribution Lines

7.5.1 Objective of Standard

This standard provides guidelines for installation, repair, and maintenance of low voltage distribution assets. The list(s) below apply to both overhead and underground lines however several utilities have chosen to divide these documents into separate standards

7.5.2 Sample of Applicable National Standards

- ANSI/IEEE C37 – ANSI family of standards for metal enclosed switchgear (various)
- ANSI/IEEE C57 – ANSI family of standards for transformers (various)
- ANSI/IEE 141 – Nominal Standard System Voltages
- IEEE 576 - Recommended Practice for Installation, Termination, and Testing of Insulated Power Cable as Used in Industrial and Commercial Applications (2000)
- NEMA VE-1 - Metal Cable Tray Systems (2009)
- IEC 61439 Low-voltage switchgear and control gear assemblies - Part 1: General rules
- IEC 60439 Low-voltage switchgear and control gear assemblies
- IEC 60947 Low-voltage switchgear and control gear - Part 1: General rules
- NFPA 70 - National Electrical Code (2014)
- NFPA 70E - Standard for Electrical Safety in the Workplace (2015)
- NFPA 101 - Life Safety Code (2015)
- NFPA 780 - Lightning Protection Code (2014)
- NEC Article 450 - Transformers

7.5.3 Sample Table of Contents Headings

Overhead Lines:

- Line Configuration: items such as: line types for expected voltages, pole construction, guy wire requirements, transformer location, installation and sizing, switchgear and control gear requirements, vegetation clearances
- Location of lines: items such as: points of attachment, placement of lines with two or more buildings on a lot
- Service Drops: items such as: vertical clearances for residential or buildings, clearance for non-residential, clearances around doors and windows, attachment specifications and requirements,
- Pole Requirements: items such as: treatment requirements, process for approving pole vendors, approved vendor list, height requirements for specific voltage levels and/or applications, installation requirements, tagging requirements,

Underground Lines:

- Underground Line Configuration: items such as: installation requirements, trenching / excavation / backfill / conduit / paving requirements, ground rod requirements, underground connector requirements and specifications

- Equipment Pads: items such as: when equipment pads are necessary, specifications for pads,
- Underground to Overhead Transition: items such as: specifications for methodology to be used to transition from underground to overhead lines
- Service Installation: items such as: connections from underground network to customer's service-termination facility, conduit installation for underground service
- Primary Service: items such as: application process for primary service and application data requirements, protection device requirements, metering requirements and configurations, testing procedures,

7.6 Plug-In Electric Vehicle Interconnections

7.6.1 Objective of the Standard

This standard provides both the customer and the utility with the requirements for notification of a pending plug-in vehicle interconnection request, the necessary steps for the utility and/or customer to take to ensure adequate service is provided without disruption to the broader distribution grid, and procedures for upgrading service if necessary

7.6.2 Sample of Applicable National Standards

- IEC 61851 – Electric Vehicle Conductive Charging System, General Requirements
- NEMA EVSE 1-2018 – EV Charging Network Interoperability Standard

7.6.3 Sample Table of Contents Headers

- Notification Requirements: items such as: notification time requirements, application process, upgrade cost requirements,
- Installation: items such as: configuration of charging equipment in conjunction with different metering configurations, installation in conjunction with installed distributed generation, signage requirements, power supply requirements, shock protection, cable assemblies, insulation requirements, short circuit protection.

7.7 Substations

7.7.1 Objective of Standard

This standard provides the guidelines for all equipment typically installed within a substation and will specify the different types and sizes of equipment necessary based on the capacity of the substation.

7.7.2 Sample of Applicable National Standards

- IEEE/ANSI 62 – Surge Arresters
- IEEE 81 - Guide for Measuring Earth Resistivity, Ground Impedance, and Earth Surface Potentials of a Ground System (2012)
- IEEE 80 - Guide for Safety in AC Substation Grounding (2015)

- IEEE 142 - Grounding of Industrial and Commercial Power Systems (2007)
- IEEE 605 - Guide for Bus Design in Air Insulated Substations (1998, per revised PSE&G requirements)
- IEEE 525 - Guide for the Design and Installation of Cable Systems in Substations (2007)
- IEEE 979 - Guide for Substation Fire Protection (2012)
- IEEE 998 - Guide for Direct Lightning Stroke Shielding of Substations (2012)
- IEEE 1375 - Guide for the Protection of Stationary Battery Systems (1998)
- IEEE 1427 - Guide for Recommended Electrical Clearances and Insulation Levels in Air-Insulated Electrical Power Substations (2006)
- IEEE 450-2002 Section 5.2.3 – Recommended Practice for Maintenance, Testing and Replacement of Vented Lead Acid Batteries for Stationary Applications
- IEEE 11188-1996, Section 5.2.2 subsections a, b & c
- IEEE 485-2010 – Recommended Practice for Sizing Large Lead Storage Batteries for Generating Stations and Substations
- IEEE 1115-2014 – Recommended Practice for Sizing Nickel-Cadmium Batteries for Stationary Application
- NFPA 70 – The National Electric Guide
- NFPA 780 – The Lightning Protection Code

7.7.3 Sample Table of Contents Headings

- Switchboards: items such as: clearance requirements, enclosure requirements, individual vs. group mounted requirements

- Substation batteries: items such as: back-up battery technologies allowed in substation applications, maintenance requirements, battery sizing methodology, installation configuration requirements,

- Transformers: items such as: sizing parameters, configuration within substations, installation requirements, maintenance requirements, transformer type requirements,

- Protective devices: items such as: fuse, low/med/high voltage circuit breaker requirements, low voltage ground fault protection, surge protective device requirements,

- Grounding: items such as: system grounding, service entrance grounding, low / medium voltage grounding, transformer grounding, lightning protection system grounding

7.8 Inverter Connected Assets

7.8.1 Objective of the Standard

As the growth of solar PV installations – both rooftop and utility scale – and energy storage systems continues across the country, a systematic view on how to interconnect the inverters from these projects to the distribution grid is necessary. This standard will help guide both CWL and applicants for interconnection as to the application process for interconnection, what is required in an application (i.e., one-line diagrams, site plans and diagrams, disconnect switch specification sheets, protective relay information, etc.), and will provide guidelines for operating parameters (i.e., is export to the grid allowable?)

7.8.2 Sample of Applicable National Standards

- UL 1741 - Inverters, Converters, Controllers, and Interconnection System Equipment for "Use with Distributed Energy Resources"
- IEC 62894: Photovoltaic inverters - Data sheet and name plate
- IEC TS 62910: Utility-interconnected photovoltaic inverters - Test procedure for low voltage ride- through measurements
- IEC 62109-1: Safety of power converters for use in photovoltaic power systems - Part 1: General requirements
- IEC 62109-2: Safety of power converters for use in photovoltaic power
- IEC 61683: Photovoltaic systems - Power conditioners - Procedure for measuring efficiency
- IEC 61727: Photovoltaic (PV) systems – Characteristics of the utility interface
- NEC 705: Interconnected Electric Power Production Sources
- IEEE 484 - Recommended Practice for Installation Design and Installation of Vented Lead-Acid Batteries for Stationary Applications (2002)
- IEEE 485 - IEEE Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications (2010)
- IEEE 1578 - Recommended Practice for Stationary Battery Electrolyte Spill Containment and Management (2007)

7.8.3 Sample Table of Contents Headings

8. *Protection and Technical Requirements*: includes items such as: types of allowable protections, requirements for dedicated transformers, what types of generation are acceptable, how/when to use smart inverters, requirements for smart inverters, relay requirements, fault detection and protection requirements, required generator protection and control functions, requirements for power export.
9. *Operational Requirements*: includes items such as: maintenance requirements, acceptable types and required specifications of manual disconnect switching based on system voltage, normal voltage operating range and voltage flicker limits, installation inspection process.
10. *Temporary / Momentary Generator Interconnections and Automatic Transfer Switches*: includes items such as: installation requirements, allowable methods for transition, transfer switch requirements, relay setting requirements

7.9 Metering Equipment

7.9.1 Objective of Standard

This standard will provide guidance on the types of meters that are acceptable for use in specific scenarios for different customer types and applications, as well as metering applications throughout the distribution network.

7.9.2 Sample of Applicable National Standards

- IEC 61869- Instrument transformers
- IEC 62052-11- Electricity metering equipment (AC) - General requirements, tests, and test conditions - Part 11: Metering equipment
- IEC 62053- Electricity metering equipment (AC) - Particular requirements - Part 24: Static meters for reactive energy at fundamental frequency
- Electric Utility Service Equipment Requirements Committee (EUSERC)

7.9.3 Sample Table of Contents Headings

- Meter Installation Requirements: items such as: location requirements, grouping allowances, meter room specifications, installation heights, cabinet enclosure specifications, clearance requirements, grounding requirements
- Meter Identification and Seals: items such as: proper identifying markers, required sealing, meter locking requirements
- Meter Types and Connections: items such as: connection diagrams for specific meters based on voltage, amps, and phases,
- Service Disconnects: items such as: specifications for meter fusible switch/circuit breaker, disconnect switch rating requirements, metering and main service switching sequence,
- Temporary Service: items such as: installation requirements for temporary meters during construction
- Switchboards: items such as: ratings requirements, configuration specifications, installation requirements, clearance and access based on service ratings

7.10 Control and Monitoring Systems

7.10.1 Objective of Standard

This standard will provide guidance on the installation of control and monitoring systems used in the electric power system. For instance, because of the sensitivity of these electronic systems to low static voltages proper grounding of these systems is critical for proper performance of these systems.

7.10.2 Sample of Applicable National Standards

- IEEE 80- Guide for Safety in AC Substation Grounding
- IEEE 81- Guide for Measuring Earth Resistivity, Ground Impedance, and Earth Surface Potentials of a Grounding System
- IEEE 665 Guide for Generating Station Grounding
- IEC 60364 (4-41) Low-voltage electrical installations – Part 4-41: Protection for safety – Protection against electric shock
- IEC 60364 (5-54) Electrical installations of buildings – Part 5-54: Selection and erection of electrical equipment – Earthing arrangements, protective conductors, and protective bonding conductors
- IEC 61140 Protection against electric shock – Common aspects for installation and equipment
- IEC 61936-1 Power installations exceeding 1 kV a.c. - Part 1: Common rules

- IEC 62305 Protection against lightning
- IEC 60099 Surge arresters
- ANSI/IEEE C62.11 for Metal-Oxide Surge Arresters for AC Power Circuits
- NEMA LA-1 for Surge Arresters
- NFPA 780 for Lightning Protection Code

7.10.3 Sample Table of Contents Headings

- System grounding
- Equipment grounding
  - Separate isolated grounds
  - Remote equipment
  - Local Area Networks
- Surge Arrestors
- Lightning Protection

7.11 Civil / Structural Design Standards

7.11.1 Objective of Standard

This standard provides the required guidelines for constructing and / or renovating physical structures involved with housing distribution grid equipment or control center functions.

7.11.2 Sample of Applicable National Standards

- International Building Code, IBC, 2015
- Minimum Design Loads for Buildings and Other Structures, ASCE 7-10
- Substation Structure Design Guide, ASCE 113, 2008
- Steel Construction Manual, 14th Edition
- Specification for Structural Steel Buildings, AISC 360-10
- Building Code Requirements for Structural Concrete, ACI 318-14
- Guide for Substation Fire Protection, IEEE 979, 2012
- National Electric Safety Code, NESC, 2012

7.11.3 Sample of Table of Contents Headings

- Design Loads
- Substation Structure Design
- Building- structural design- steel and concrete
- Substation Fire Protection- structural design

7.12 Implementation Plan

7.12.1 Prioritization and Schedule

While ideally CWL would develop and implement the complete set of the standards outlined in this report, it may not be feasible for CWL to create the complete set envisioned in this report due to financial and time constraints or at develop them all at once. To that end, the highest priority standards (or those developed first) should be those that address important new and emerging technical areas. This is based on the observation that CWL is successfully performing on its traditional asset areas and the standards on new and emerging areas are needed to help guide the staff's work in these, less familiar areas. The standards that cover more traditional assets could then be developed in later efforts. The plan also considers CWL's existing engineering drawing standards. They will be incorporated where appropriate into the new standards. For instance, the comprehensive set of CWL drawings around overhead distribution will be incorporated into the new standard and be an integral part of the new standard.

The first tranche of standards to be developed cover the new, emerging areas. The second and third tranches cover the more complicated existing classes of assets and the remaining proposed standards, respectively. The three tranches are:

1. Tranche One

    4. General
    5. Plug-In Electric Vehicle Interconnections
    6. Inverter Connected Assets

2. Tranche Two

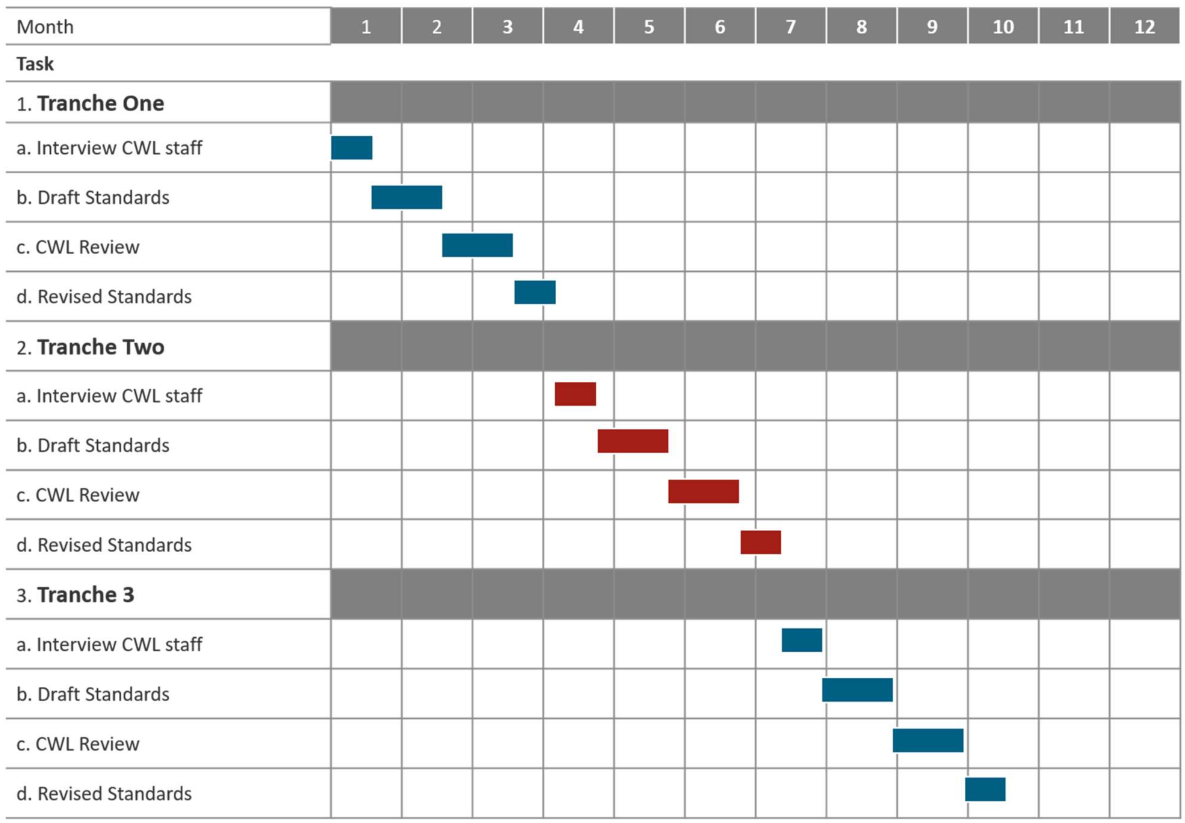
    7. Control and Monitoring Systems
    8. Substations
    9. Metering Equipment

3. Tranche Three

    10. Low Voltage Distribution Lines (overhead and underground)
    11. Civil/Structural Design

The overall schedule of developing all three tranches of standards is shown below, assuming the three tranches are undertaken consecutively with no time gaps between the completion of one tranche and the beginning of another. Each tranche is anticipated to be completed in slightly over three months, which includes one month for CWL review and comment.

Figure 7-1 Schedule to Develop Standards



7.12.2 Estimated Budget

Assuming no gaps between tranches and one team trip (2-people) to Columbia (from Washington, DC) for each tranche, we estimate the following costs to complete each tranche:

4. Tranche 1- $142,000
5. Tranche 2- $139,000
6. Tranche 3- $108,000

7.13 North American Electricity Reliability Corporation (NERC) Registrations

7.13.1 Introduction and Background

Columbia Water and Light (CWL), as part of a broader effort, requested that the Siemens team, and Advisian in particular, examine CWL's current North American Electric Reliability Corporation (NERC) Functional Registrations to offer suggestions on maintaining the current registrations or not considering the forecasted functions as identified in the IRP and Master Plan. The table below shows the current NERC Functions for which CWL is registered.

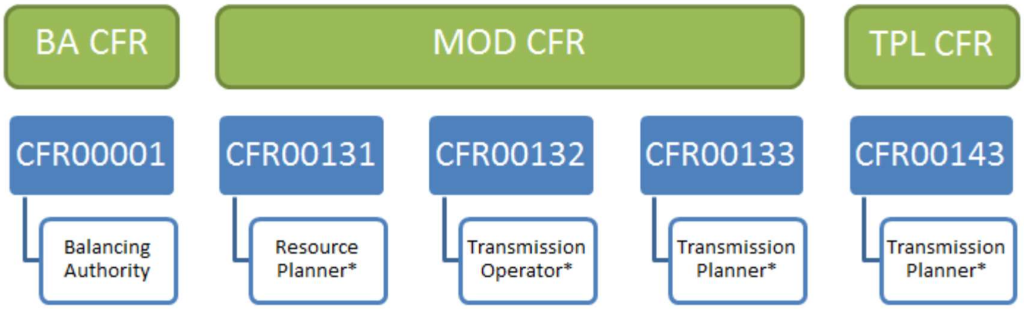
CWL Registered NERC Functions and Definitions	
Functional Registration	NERC Definition*
Balancing Authority (BA)	The responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real-time.
Resource Planner (RP)	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific Loads (customer demand and energy requirements) within a Planning Authority area.
Transmission Operator (TOP)	The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission Facilities.
Transmission Planner (TP)	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.
Transmission Owner (TO)	The entity that owns and maintains transmission Facilities.
Distribution Provider (DP)	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.
*From NERC Document: Appendix 5B – Statement of Compliance Registry Criteria (Revision 6) 2016	

CWL has entered into Coordinated Functional Registration (CFR) agreements with Midcontinent Independent System Operator (MISO). A CFR is an arrangement between multiple entities registered for a NERC function to clearly identify and assign compliance responsibilities between those entities. CFR Registered Entities can have two roles:

1. Lead registered entity, a.k.a. the CFR Point of Contact
2. Participant registered entity

The figure below shows the various CFRs that CWL has with MISO. CWL is the lead registered entity for all functions except Balancing Authority. CWL is a participant registered entity for the Balancing Authority role with MISO as the lead registered entity.

Figure 7-2 NERC CFRs



On January 6, 2009, MISO assumed the role of Balancing Authority for its members. CWL now operates as a Local Balancing Authority under the direction of MISO (JRO/CRF filed with NERC/FERC). MISO is now responsible for CPS, DCS, generator dispatch, contingency reserves, etc. CWL is required to maintain BA status, staff with NERC certified operators, and provide meter data to MISO.

7.13.2 NERC Registrations Requirements

NERC defines "Bulk Electric System" (BES) as all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. NERC, in its *2016 Appendix 5B Statement of Compliance Registry Criteria* states, "Any entity reasonably deemed material to the reliability of the BES will be registered, irrespective of other considerations." While there are exceptions for small entities, they do not apply to Distribution Provider systems serving lower than75 MW of peak Load that is directly connected to the BES.

7.13.3 Comparative Analysis

A key question around NERC registrations is how do CWL's registrations compare to similar municipal utilities. While there are hundreds of entities to potentially compare CWL with, Advisian selected five other municipal utilities to benchmark against. In addition to roughly comparable size, load, and capacity, utilities that that owned transmission assets were used as selection criteria. While no such comparison is perfect, the following tables with provide some insight into how CWL compares with similar municipal utilities. The first table provides information on the size and other parameters of the utilities.

Utilities Selected for Comparison with CWL				
Utility	Regional Compliance Authority	Customers	load (MW)	generation (MW)
CWL	**SERC**	**48,000**	**260**	**191**

Utilities Selected for Comparison with CWL				
Colorado Springs (CO)	WECC	229,000	900	1000
Independence MO	MRO	57,000	300	380
Madison Gas & Electric (WI)	MRO	155,000	700	650
Springfield City Water, Light & Power (IL)	SERC	60,000	300	724

The following table shows which NERC Functions each utility is registered for. The list below defines the abbreviations used in this table:

1. BA- Balancing Authority
2. DP- Distribution Provider
3. GO- Generator Owner
4. GOP- Generator Operator
5. PA/PC- Planning Authority/Planning Coordinator
6. RC- Reliability Coordinator
7. RP- Resource Planner
8. RSG- Reserve Sharing Group
9. TO- Transmission Owner
10. TOP- Transmission Operator
11. TP- Transmission Planner
12. TSP- Transmission Service Provider

Comparison of NERC Registrations for Selected Utilities												
Utility	BA	DP	GO	GOP	PA/PC	RC	RP	RSG	TO	TOP	TP	TSP
CWL	✓	✓					✓		✓	✓	✓	
Colorado Springs CO		✓	✓	✓	✓		✓		✓	✓	✓	✓

Comparison of NERC Registrations for Selected Utilities												
Independence MO		✓	✓	✓			✓		✓	✓	✓	
Madison MGE WI	✓	✓	✓	✓			✓					
Springfield CWPL IL	✓	✓	✓	✓			✓		✓	✓	✓	

All the utilities have around the same number of NERC registrations. Springfield CWPL may be the most comparable since it has the same regional compliance authority as CWL, SERC. Springfield CWPL is registered for the same functions as CWL, plus two additional registrations, GO and GOP. CWL owns generation at Power Plant and the Columbia Energy Center although it does not generally export generation to the BES in any material amount, whereas Springfield (and the other utilities) does export generation capacity and this is why Springfield holds GO and GOP registrations and CWL does not.

7.13.4 Recommendations

NERC rules around materiality to the BES state that entities with more than 75 MW of BES connected load are required to be registered for functions the entity normally performs. Since CWL has more than 75 MW of connected load and does perform actions consistent with its registered NERC functions, it is recommended that CWL maintain its current registrations. Additionally, under the IRP, CWL is expected to continue purchasing the bulk of its power via PPA and is not expected to own generation that could be exported to the BES, so GO/GOP registration is not expected to be required.

The various CFRs in place with MISO appear to be a reasonable approach to sharing the burdens of fulfilling NERC functions. This was confirmed with an interview with several MISO staff familiar with MISO's CFRs.

In addition, utilities similar to CWL hold the same NERC registrations as CWL, in general. This is indicative that CWL is "right-sized" with respect to its NERC registrations.

8 Capital Projects

8.1 Transmission Investment Summary

As presented in Section 5 of this report no investments were identified for compliance with NERC reliability standards or CWL planning guidelines. However, instances of load shedding under N-1-1 conditions were noted and a non-wires alternative to address it was proposed.

This alternative consists of a 27 MW 4 hours battery energy storage and a 30 MW (AC) solar array and is expected to have a cost of $ 68 million as shown below and detailed in Section 5.7.2

Table 8-1: Non Wires Alternative Capital Cost

	MW	$/kW	Capital Cost $M
Storage (BESS)	27	1,234	33.3
PV	30	1,154	35.6
Total			**67.9**

However, to properly assess the cost of this alternative it is necessary to account for its benefits on achieving the IRP goals and as shown in section 5.7.3 when the NWA are added to the Reference Case resulting in advancing PV generation and the incorporation of more storage than in the original case, we see that the net present value of the revenue requirements increases by $41.7 million which is the true cost to CWL and 61% of the capital expenditure (39% reduction).

Table 8-2: Present Value of Costs at 5% discount rate ($000)

	Reference Case	NWA Analysis	Difference NWA vs. Reference
Variable Costs ($,000)	$158,518	$158,612	$95
Fuel Costs ($,000)	$48,937	$36,406	($12,531)
Emission Costs ($,000)	$42,701	$30,759	($11,942)
Total Fixed Costs ($,000)	$493,748	$566,719	$72,971
REC Costs ($,000)	$528	$147	($381)
Capacity Market Purchases ($000)	$18,369	$13,499	($4,870)
Energy Market Purchases ($,000)	$36,743	$48,005	$11,261
Energy Market Sales ($,000)	$153,388	$166,259	$12,872
Total Cost ($,000)	$799,544	$854,146	$54,602
Total Cost After Market Sales ($,000)	**$646,156**	**$687,886**	**$41,730**

In the Transmission Section it was also confirmed the need to reinforce the system by upgrading the 69 kV line from Hinkson Creek to University (UMC) to 107 MVA and as shown in section 7.10 CWL should consider increasing the rating of this new line to 122 MVA to support a potential request of firm transmission service by UMC

In addition to the above, CWL is currently considering other transmission expansions to address the limitations of its system under N-1-1 that can lead to load shedding. These options considered include a) new 161 kV line Perche Creek to Grindstone, b) new 161 kV line Perche Creek to Bolstad, c) new 161 kV line Perche Creek to Mc Bain substation and d) a new 161 kV connecting Perche Creek to Ameren 345 kV system via a new 345 /161 kV substation

These options are alternatives to the NWA presented above and are expected to be under $ 30 million, which would make the NWA more costly.

8.2 Distribution Investment Summary

This section provides a summary of distribution level capital expenditures based on the results of Section 5. The distribution level investments cover transmission to distribution substation investments, medium voltage investments and medium voltage to low voltage transformers. Low voltage investments are too granular to become part of our forecast. Investment priority is also provided.

8.2.1 Project Prioritization Methodology

In distribution network planning, each project is prioritized according to the recurrence or the issue that it addresses, normal or contingency conditions and the severity of the violation. Projects that address higher overloads generally have higher priority and become urgent if those are expected to appear under normal conditions. By prioritizing the projects, efficient utilization of the limited funds can be made.

We summarize below the considerations made used for prioritization of CWL projects:

13. **Violation condition:** In which operating state (normal or emergency condition) the issue is appeared. Projects that address violations under normal conditions have the highest priority.
14. **Total Affected Load:** This is measured by the level of overload that would occur, typically on a backup feeder during an outage, without the investment. It is proportional to the load that would have to remain disconnected until repairs are done on the affected feeder.
15. **Number of affected customers**: This is determined by the Total Affected Loads and the load per customer for each individual feeder. It estimates how many customers would be interrupted.
16. **Number of affected feeders:** It measures how many feeders are impacted by the same limitation and would be benefited by the investment.
17. **Voltage violation:** This is measured by the level of voltage drop that would occur on the existing backup feeder (or affected feeder) during an outage on the affected feeder without the investment.

Based on the above, we rank the projects according to the following.

1. Violations in normal condition should be addressed with highest priority.
2. Next issues that appeared during emergency condition are addressed with higher priority to those that address high levels of Affected Load.
3. If the Affected Load is the same, investments that provide backup to more feeders have higher priority.
4. Capacitor banks for power factor control and voltage profile improvement.

8.2.2 Unit Cost and Capital Expenditure Methodology

The unit costs used for CWL capital expenditure calculations are shown in Table 8-3. These costs are typical for Midwest continental of US.

Table 8-3: The selected unit costs for CWL CapEx calculations

Cables	Unit Cost [$/mile]
Underground feeder, 3# 500 kcmil CU	$1,521,492
Capacitor Banks	**Unit Cost [$]**
300 kVAr	$4,073
600 kVAr	$8,146
900 kVAr	$12,220
1200 kVAr	$16,293
Switching Equipment	**Unit Cost [$]**
Breaker - HV	$673,272
Breaker - MV	$149,085
Switch 600 Amp Class	$80,250
Distribution Transformers	**Unit Cost [$/kVA]**
Transformer	$233
Power Transformers	**Unit Cost [$/MVA]**
Transformer	$29,438

With respect of these cost and their application, we note the following

- 500 kcmil CU underground cable unit cost is the total which includes cable, trenching and substructure costs.
- For both power and distribution transformers, unit cost includes all hardware costs for connection.
- Pad-mounted Switches considered.
- When costing new feeders section cost, we include the cable cost and at least one switch cost.
- For the new feeders costing, we include cable cost, at least one switch and one breaker cost. This is the general approach for capital expenditure calculation; however, it was finetuned by project basis.
- For substation expansion, power transformer, one HV breaker and one MV breaker are considered.
- For capacitor banks, 300 kVAr and multiples are considered in accordance with the planning criteria. Unit cost for capacitor banks includes all hardware costs for connection.

8.2.3 CWL – Overall Capital Expenditure Budget

Capital expenditure budget was calculated separated in distribution system and transmission to distribution substations. The distribution system budget is based on comprehensive analysis and includes cost of underground cable, switching equipment, distribution transformer and capacitor banks. Transmission level budget includes the power transformer and one HV and MV breaker costs. The total CWL CapEx budget for each term is shown in Table 8-4.

Table 8-4: CWL CapEx budget for each term

CWL Investments	Cost [$]			
	2025	2030	2040	Total
Distribution Level	**$36,869,668**	**$2,933,495**	**$6,555,517**	**$46,358,680**
Underground Cable	$18,580,462	-	-	$18,580,462
Breaker & Switches	$3,473,932	-	$80,250	$3,554,182
Distribution Transformer	$14,456,835	$2,892,763	$6,340,852	$23,690,450
Capacitor Bank	$358,440	$40,732	$134,415	$533,587
Transmission Level	**$4,610,134**	**$0**	**$0**	**$4,610,134**
Power Transformer	$2,143,063	-	-	$2,143,063
Breaker	$2,467,071	-	-	$2,467,071
Total	**$41,479,802**	**$2,933,495**	**$6,555,517**	**$50,968,814**

We provide details on this budget next

8.2.4 Distribution System Investment

Distribution system investments were grouped in projects, and these projects were prioritized using the criteria presented earlier. Table 8-5 shows the priority of these projects.

As shown in Table 8-5, the first two projects (Project 15 and Project 11) address an issue under the system intact or normal conditions. Project 15 addresses overloading violation on a section of feeder GS231 out of Grindstone substation and Project 11 addressed a voltage drop violation on PC221 out of Perche Creek substation. As noted in Table 8-5, the central driver for the prioritization is the Affected Load. These projects are described in detail in the workpapers provided with this report and are presented in the next sections.

Table 8-5: Prioritized project list and related details

Priority	Project Name	Violation Condition	Total Affected Load	Number of Affected Customers	Number of Affected Feeders	Voltage Violation
1	Project 15	Normal	1.47	187	1	-
2	Project 11	Normal	0.00	0	3	98.3
3	Project 20	Emergency	8.12	2404	3	96.3
4	Project 8	Emergency	7.48	1724	7	97.9
5	Project 19	Emergency	4.20	959	2	-
6	Project 12	Emergency	3.62	76	1	-
7	Project 16	Emergency	2.95	375	2	-
8	Project 7	Emergency	2.63	538	2	-
9	Project 9	Emergency	2.11	723	2	-
10	Project 13	Emergency	1.91	436	1	-
11	Project 4	Emergency	1.87	95	2	98.1
12	Project 17	Emergency	1.83	559	3	-
13	Project 6	Emergency	1.61	203	1	98.8
14	Project 2	Emergency	1.01	2	1	-
15	Project 1	Emergency	1.01	39	2	-
16	Project 18	Emergency	0.93	8	1	-
17	Project 14	Emergency	0.55	145	1	-
18	Project 5	Emergency	0.54	137	1	-
19	Project 10	Emergency	0.29	55	1	98.5
20	Project 3	Emergency	0.00	0	1	98.8

8.2.4.1 Underground Cable Investments

The prioritized total investment in underground cables is shown in Table 8-6 that shows the new line length and cost for each project.

Project 11 has the highest cost and high priority. This is the project to provide a new feeder out of Perche Creek substation to addresses voltage and loading issues. It also provides a second source to the residential area to the south, close to water treatment facility.

The second highest cost project with respect of underground cables is in Project 17. Project 17 addresses overloading during emergency condition on feeder RH214 as it tries to provide backup to RH224 out of Rebel Hill substation.

As mentioned before, 500 kcmil CU is used for the new investments as these are mainlines and in accordance with the planning criteria.

Table 8-6: Prioritized project list with line investment details

Priority	Project Name	Total Line Length [mi]	Line Cost [$]
1	Project 15	0.065	$98,897
2	Project 11	4.831	$7,350,328
3	Project 20	1.389	$2,113,353
4	Project 8	0.079	$120,198
5	Project 19	0.799	$1,215,672
6	Project 12	0.005	$7,607
7	Project 16	0.391	$594,903
8	Project 7	0.003	$4,564
9	Project 9	0.002	$3,043
10	Project 13	0.314	$477,749
11	Project 4	1.132	$1,722,329
12	Project 17	2.188	$3,329,025
13	Project 6	0.197	$299,734
14	Project 2	0.012	$18,258
15	Project 1	0.227	$345,379
16	Project 18	0.06	$91,290
17	Project 14	0.007	$10,650
18	Project 5	0.509	$774,439
19	Project 10	-	-
20	Project 3	0.002	$3,043
	Total	**12.212**	**$18,580,462**

The investments in cables are largely for new feeders, but there are investments in replacing the cables by a larger cross section cable, which can be called reconductoring. Table 8-7 shows the split of these costs.

Table 8-7: Split of cable investments

Feeder	Total Line Length [mi]	Line Cost [$]
New Feeder	11.079	$16,856,611
Reconductor	1.133	$1,723,851
Total	**12.212**	**$18,580,462**

Further to the above the new feeder section investments can be split into two components, new sections along existing feeders and sections for new feeders. This is shown Table 8-8 and Table 8-9.

Table 8-10 provides reconductoring details by substation.

Table 8-8: New sections along the existing feeders

	New Sections		
Substation	Feeder Name	Type	Length [mi]
Bolstad	BD213	500 CU	0.002
Bolstad	BD223	500 CU	0.227
Grindstone	GS211	500 CU	0.391
Grindstone	GS232	500 CU	0.007
Harmony Branch	HB231	500 CU	2.285
Rebel Hill	RH221	500 CU	0.060
Rebel Hill	RH223	500 CU	0.799
		Total	3.771

Table 8-9: New sections along the new feeders

	New Sections		
Substation	Feeder Name	Type	Length [mi]
Bolstad	BD231_ST	500 CU	1.144
Perche Creek	PC231_ST	500 CU	0.079
Perche Creek	PC232_ST	500 CU	2.548
Rebel Hill	RH231_ST	500 CU	1.349
Rebel Hill	RH232_ST	500 CU	2.188
		Total	7.308

Table 8-10: Reconductoring along the feeders

	Reconductoring		
Substation	Feeder Name	Type	Length [mi]
Blue Ridge	BR212	500 CU	0.213
Grindstone	GS231	500 CU	0.065
Harmony Branch	HB233	500 CU	0.005
Hinkson Creek	HC231	500 CU	0.314
Power Plant	PP212	500 CU	0.296
Power Plant	PP221	500 CU	0.003
Power Plant	PP223	500 CU	0.197
Rebel Hill	RH231_ST	500 CU	0.040
		Total	1.133

8.2.4.1.1 Breaker and Switches

As described in Section 5, there is a total of 5 new feeders are proposed and new breakers are required for these new feeders. These are included in the below.

- Project 4 – BD231_ST out of Bolstad substation
- Project 8 – PC231_ST out of Perche Creek substation
- Project 11 – PC232_ST out of Perche Creek substation
- Project 17 – RH232_ST out of Rebel Hill substation
- Project 20 – RH231_ST out of Rebel Hill substation

With respect of the switches, there are 34 new switches identified and most of them are associated with specific projects as shown in Table 8-11. However, there are 7 new switches that were located to sectionalize the system and allow more efficient transfer of load between feeders. The total cost of breakers and switches for each term is shown in Table 8-12.

Table 8-11: Breaker and switch investments in assigned projects

Priority	Project Name	2025 Number of Breaker	2025 Number of Switch	2025 Breaker Cost [$]	2025 Switch Cost [$]	2025 Total Cost in 2025 [$]	2040 Number of Breaker	2040 Number of Switch	2040 Breaker Cost [$]	2040 Switch Cost [$]	2040 Total Cost in 2025 [$]	Total Cost
1	Project 15	0	0	$0	$0	$0	0	0	$0	$0	$0	
2	Project 11	1	4	$149,085	$321,001	$470,086	0	0	$0	$0	$0	
3	Project 20	1	3	$149,085	$240,751	$389,836	0	0	$0	$0	$0	
4	Project 8	1	5	$149,085	$401,251	$550,336	0	0	$0	$0	$0	
5	Project 19	0	3	$0	$240,751	$240,751	0	0	$0	$0	$0	
6	Project 12	0	0	$0	$0	$0	0	0	$0	$0	$0	
7	Project 16	0	0	$0	$0	$0	0	0	$0	$0	$0	
8	Project 7	0	0	$0	$0	$0	0	0	$0	$0	$0	
9	Project 9	0	1	$0	$80,250	$80,250	0	0	$0	$0	$0	
10	Project 13	0	0	$0	$0	$0	0	0	$0	$0	$0	
11	Project 4	1	1	$149,085	$80,250	$229,335	0	0	$0	$0	$0	
12	Project 17	1	2	$149,085	$160,500	$309,585	0	0	$0	$0	$0	
13	Project 6	0	1	$0	$80,250	$80,250	0	0	$0	$0	$0	
14	Project 2	0	0	$0	$0	$0	0	0	$0	$0	$0	
15	Project 1	0	3	$0	$240,751	$240,751	0	0	$0	$0	$0	
16	Project 18	0	1	$0	$80,250	$80,250	0	0	$0	$0	$0	
17	Project 14	0	0	$0	$0	$0	0	0	$0	$0	$0	
18	Project 5	0	0	$0	$0	$0	0	0	$0	$0	$0	
19	Project 10	0	1	$0	$80,250	$80,250	0	0	$0	$0	$0	
20	Project 3	0	2	$0	$160,500	$160,500	0	0	$0	$0	$0	
21	Sectionalizing	0	7	$0	$561,751	$561,751	0	1	$0	$80,250	$80,250	
	Total	5	34	**$745,426**	**$2,728,506**	**$3,473,932**	0	1	**$0**	**$80,250**	**$80,250**	**$3,554,182**

Table 8-12: Total cost of breakers and switches for each term

	2025		2030		2040		Total	
Equipment	**Number**	**Cost [$]**	**Number**	**Cost [$]**	**Number**	**Cost [$]**	**Number**	**Cost [$]**
Switch	34	$2,728,506	-	-	1	$80,250	35	$2,808,756
Breaker	5	$745,426	-	-	-	-	5	$745,426
Total	**39**	**$3,473,932**	**-**	**-**	**1**	**$80,250**	**40**	**$3,554,182**

8.2.4.1.2 Distribution Transformers

The spatial load forecast provided a detailed indication where the load was likely to grow. The need for new distribution transformers was assessed based on the output from spatial load forecast. Accordingly, high level of cost estimation for distribution transformers are calculated and shown in Table 8-13 for each term.

Table 8-13: Total cost of distribution transformers for each term

Dist. Transformers	2025	2030	2040	Total
Total Installed Power [MVA]	62.11	12.43	27.24	101.79
Total Cost [$]	**$14,456,835**	**$2,892,763**	**$6,340,852**	**$23,690,450**

8.2.4.1.3 Capacitor Banks

Capacitor banks were added to the network as detailed in Table 8-14 to improve voltage profile and power factor correction. The cost of capacitor banks is provided in Table 8-15.

Table 8-14: Total cost of capacitor banks for each term

Substation List	2025				2030				2040			
	300 kVAr	600 kVAr	900 kVAr	1200 kVAr	300 kVAr	600 kVAr	900 kVAr	1200 kVAr	300 kVAr	600 kVAr	900 kVAr	1200 kVAr
Blue Ridge	0	0	0	1	0	0	0	0	1	0	0	0
Bolstad	1	2	2	1	1	2	0	0	2	4	2	0
Grindstone	0	3	2	1	0	0	1	0	0	0	0	1
Harmony Branch	0	1	1	0	0	0	0	0	0	0	0	0
Hinkson Creek	2	0	1	0	0	0	0	0	1	0	0	1
Perche Creek	1	0	0	2	0	0	0	0	0	0	0	0
Power Plant	1	2	3	0	1	0	0	0	1	0	1	0
Rebel Hill	3	3	1	2	1	0	0	0	3	0	0	0
Total	8	11	10	7	3	2	1	0	8	4	3	2

Table 8-15: Total cost of capacitor banks for each term

Capacitor Banks	2025	2030	2040	Total
Number of Capacitor Banks	36	6	17	59
Total Reactive Power [MVAr]	26.4	3	9.9	39.3
Total Cost [$]	**$358,440**	**$40,732**	**$134,415**	**$533,587**

8.2.4.2 Transmission Level Investments

As shown in Section 4 and confirmed in Section 5, Bolstad, Rebel Hill and Perche Creek substation were identified as requiring a new transformer by 2025 to increase transformer capacity. The expected investment for each substation is shown in Table 8-16. It should be noted that there are available space and minimum investments are required for site preparation.

Table 8-16: Total cost of transmission level investments

		2025						
Substation	Voltage	Power Trf [MVA]	HV Breaker	MV Breaker	Trf. Cost [$]	HV Breaker Cost [$]	MV Breaker Cost [$]	Total Cost [$]
Bolstad	69/13,8 kV	22.4	1	1	$659,404	$673,272	$149,085	$1,481,761
Rebel Hill	161/13,8 kV	28	1	1	$824,255	$673,272	$149,085	$1,646,612
Perche Creek	69/13,8 kV	22.4	1	1	$659,404	$673,272	$149,085	$1,481,761
				Total	**$2,143,063**	**$2,019,815**	**$447,255**	**$4,610,134**

8.2.5 Non-Wires Alternative (NWA) in South of Perche Creek

An alternative to partially replace Project 11 is via a 4.6 MW 4-hours battery energy storage system (BESS) coupled with a 3.5 MW PV array provide similar levels of reliability to the residential area in south of Perche Creek substation as the wired solution proposed in Project 11 consisting of a new underground cable section (2.5 mi 500 kcmil CU) terminated in two switches.

The estimated capital cost of this non-wire alternative (NWA) is approximately $10 million as shown in Table 8-17. However, this BESS and PV do contribute to CWL to meet its IRP goals and this benefit implies to a reduction of 39% (see section 8.1 for further details on how this 39% reduction was derived). Once this reduction is considered the effective cost of the NWA becomes $6.3 million

This cost however is 58% higher than the cost of the conventional option ($ 4 million) as shown in Table 8-18.

Table 8-17: Total cost of non-wire alternative

Non-Wire Alternative	MW	$/kW	Capital Cost [$]	Small System Adder
Storage (BESS) - 4-hour	4.6	1,296	$5,960,220	1.05
PV	3.5	1,212	$4,240,950	1.05
Total			**$10,201,170**	
Cost reduction due to system benefits			39%	
Effective Cost			**$6,265,980**	

Table 8-18: Total cost of conventional alternative

Conventional Alternative						
Total Line Length [mi]	Number of Breaker	Number of Switch	Line Cost [$]	Breaker Cost [$]	Switch Cost [$]	Total Cost [$]
2.502	0	2	$3,806,773	$0	$160,500	**$3,967,274**

