# Payson City Power

# Capital Facility Plan

# 2024-2029

**February 15, 2024**

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# FIGURES AND TABLES

# 1. BACKGROUND

## 1.1 Introduction

This report was prepared to document the capital improvements that are required to continue to meet the requirements of the Payson City electrical power system during the period 2024-2029. The Payson City Power Department is responsible for distributing power to consumers within the city of Payson, Utah, in Utah County. The Payson City power service area includes all of the incorporated city of Payson, about 13 square miles in area. As of 2023, the city serves about 8,181 customers. The coincident peak power demand of the Payson City power system was 33.79 megawatts (MW) in August 2023.

This study analyzes the existing Payson City power system for its current capacity and analyzes the anticipated load growth to determine the improvements necessary to continue to provide service to consumers throughout the study period. The study was performed with the power system as it was configured in August 2023.

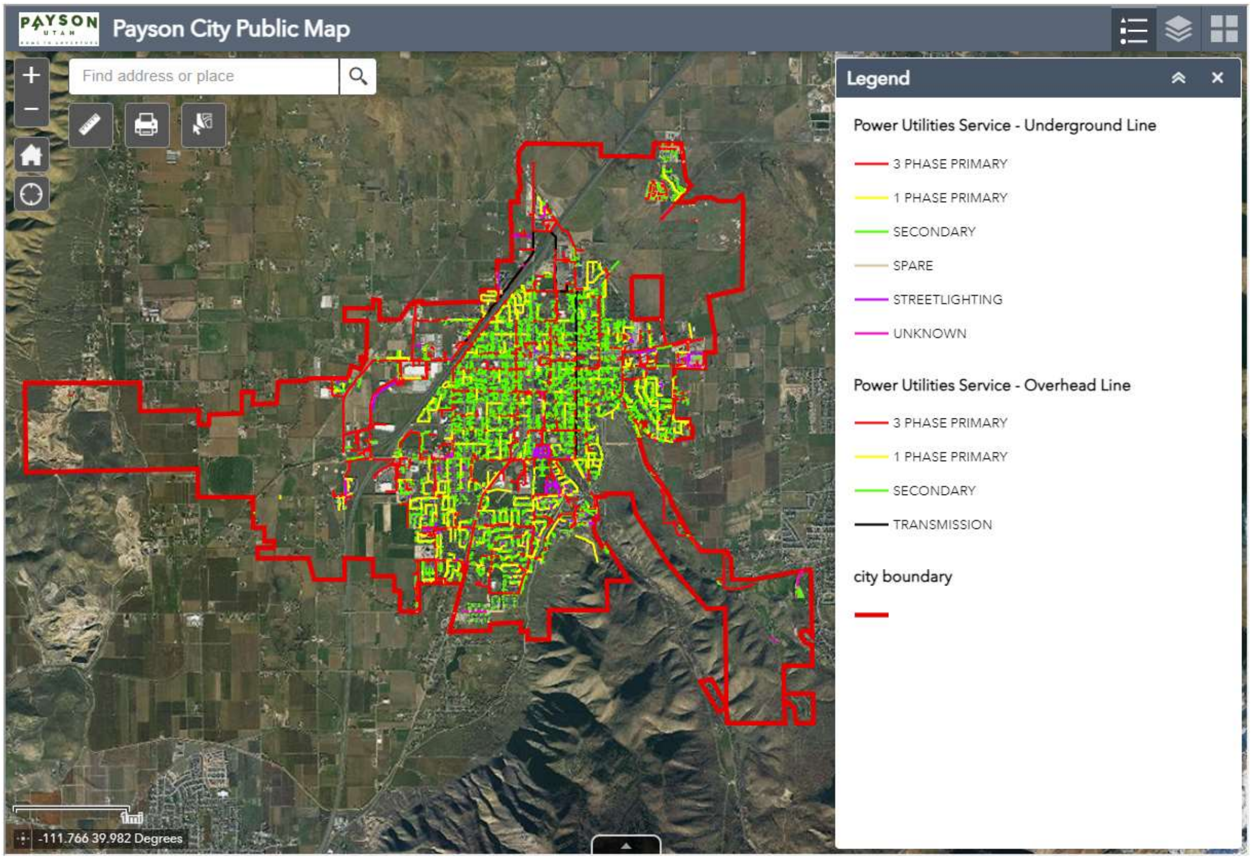


**Figure 1. Payson City Power Distribution System Map**

## 1.2 Population

The 2010 Census population of Payson City was 18,294. The 2020 Census population of Payson City was 21,101. The projected 2023 population is 23,869. The graph below shows the census population from 2020 and projected population 2020-2032 based on an average growth rate of 3.83% per year.

Development is moving north, south, and west from Payson center, with commercial development planned west of Interstate 15. This trend is predicted to continue for several decades, and the community is projected to grow rapidly for at least two decades. According to this scenario, the city will have a projected population of 30,000 by 2030. Growth is expected to slow after that date, growing at a projected AAGR of 2.1% until reaching a build-out population. The projected population of Payson is about 65,000 in 2050 to 2060.

The bulk of recent growth has taken place in the north portion of the city, with future growth anticipated to move to the west and further to the south, especially west of Interstate 15 where large mixed-density residential projects are anticipated.

## 1.3 Land Use/Development/Growth

The Payson City population growth projections are directly linked to the residential and commercial development that is currently planned or anticipated to be built in the next 10 years. As of November 2023, there were multiple residential and commercial developments proposed and moving through the city's planning and approval process. These proposed developments are estimated to add substantial power demand to the Payson City power system. Figure 2 shows the current and planned city boundary. The future land use designations in various areas of the city from the Payson General Plan is shown on the future land use map in Figures 3. The future growth potential for the city through annexation has been considered in this study.

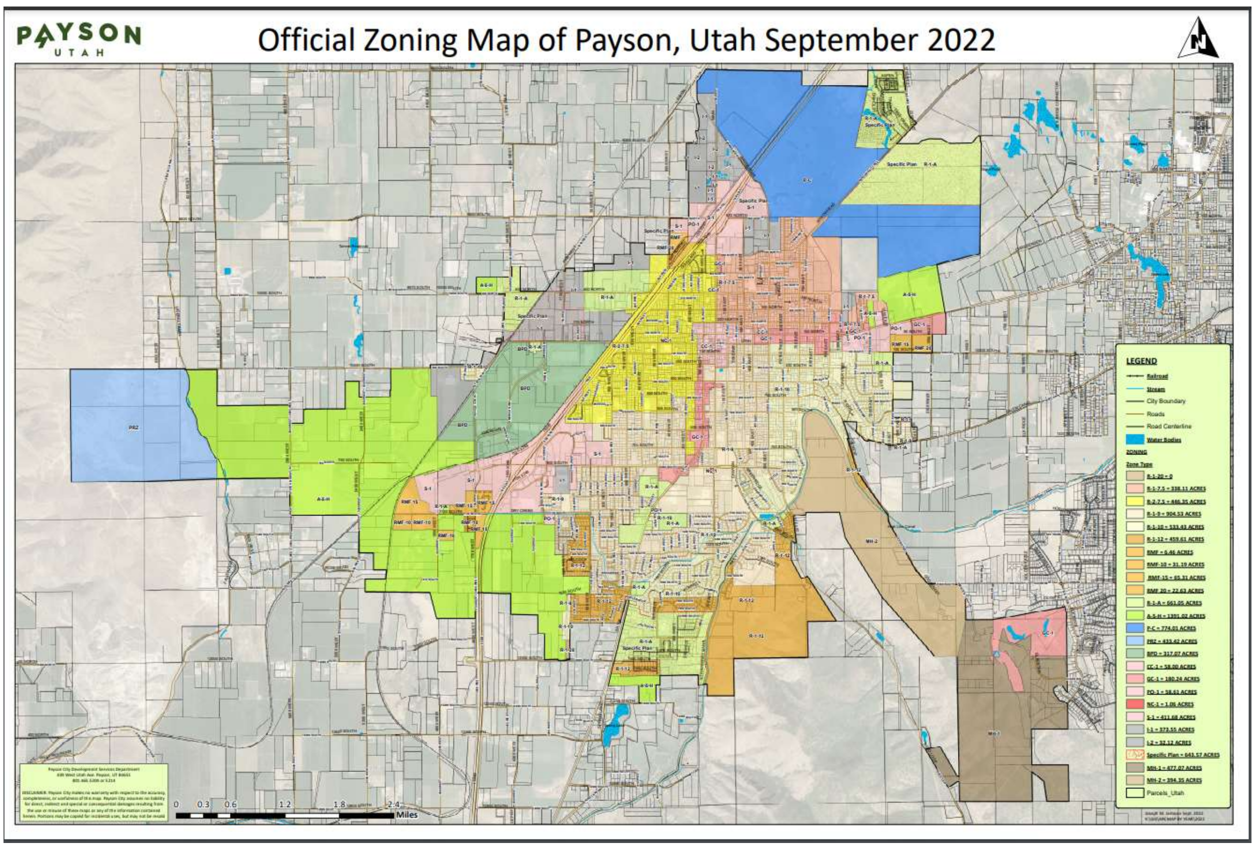


**Figure 2. Current and Planned city Boundary and Communities Map**

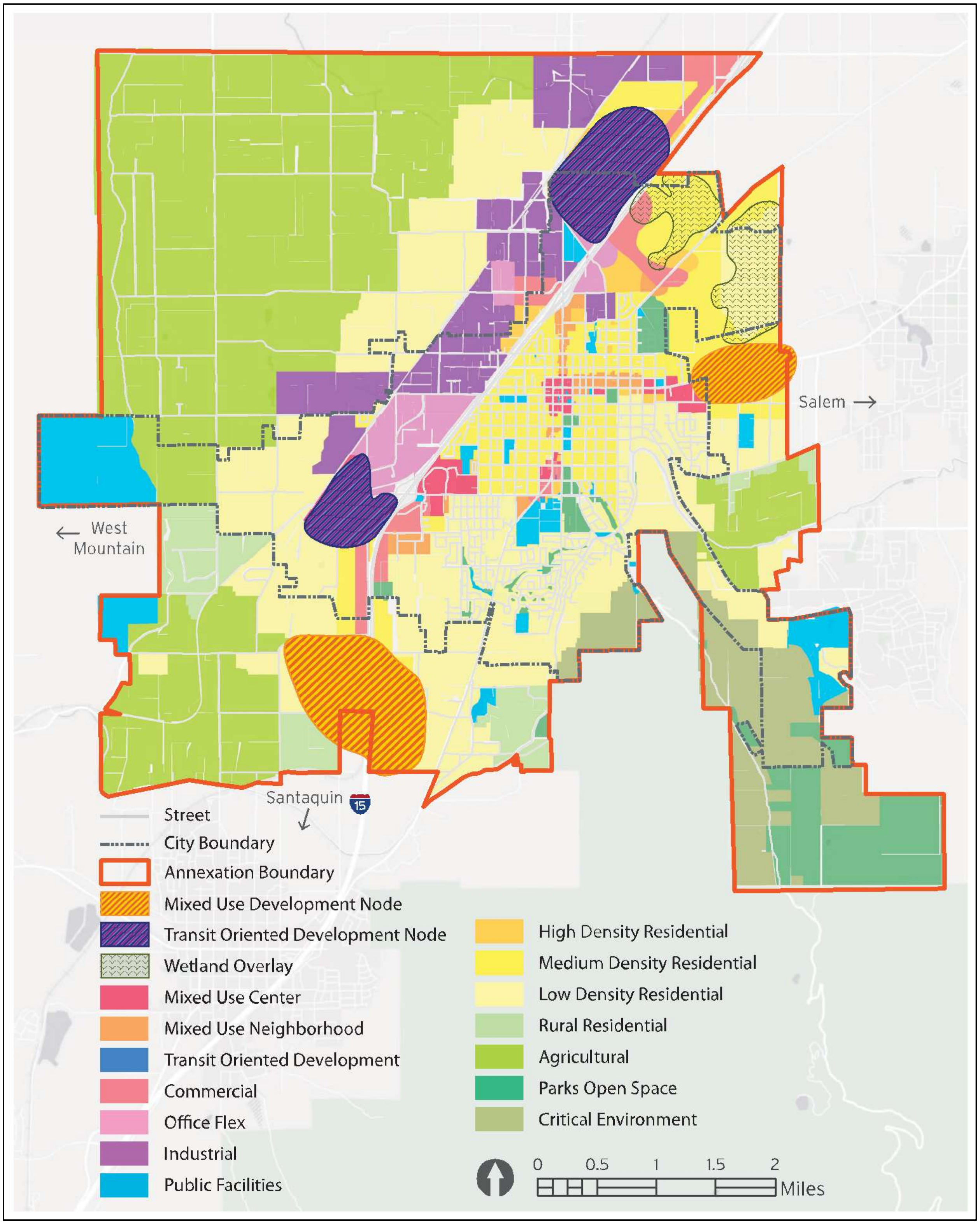


**Figure 3. Payson City Future Land Use Map, General Plan**

## 1.4 Growth Map

Some areas within the city are built-out or slowly growing while others are projected to be developed and grow rapidly. The currently proposed major development areas and areas of potential developments are shown in Figure 4.

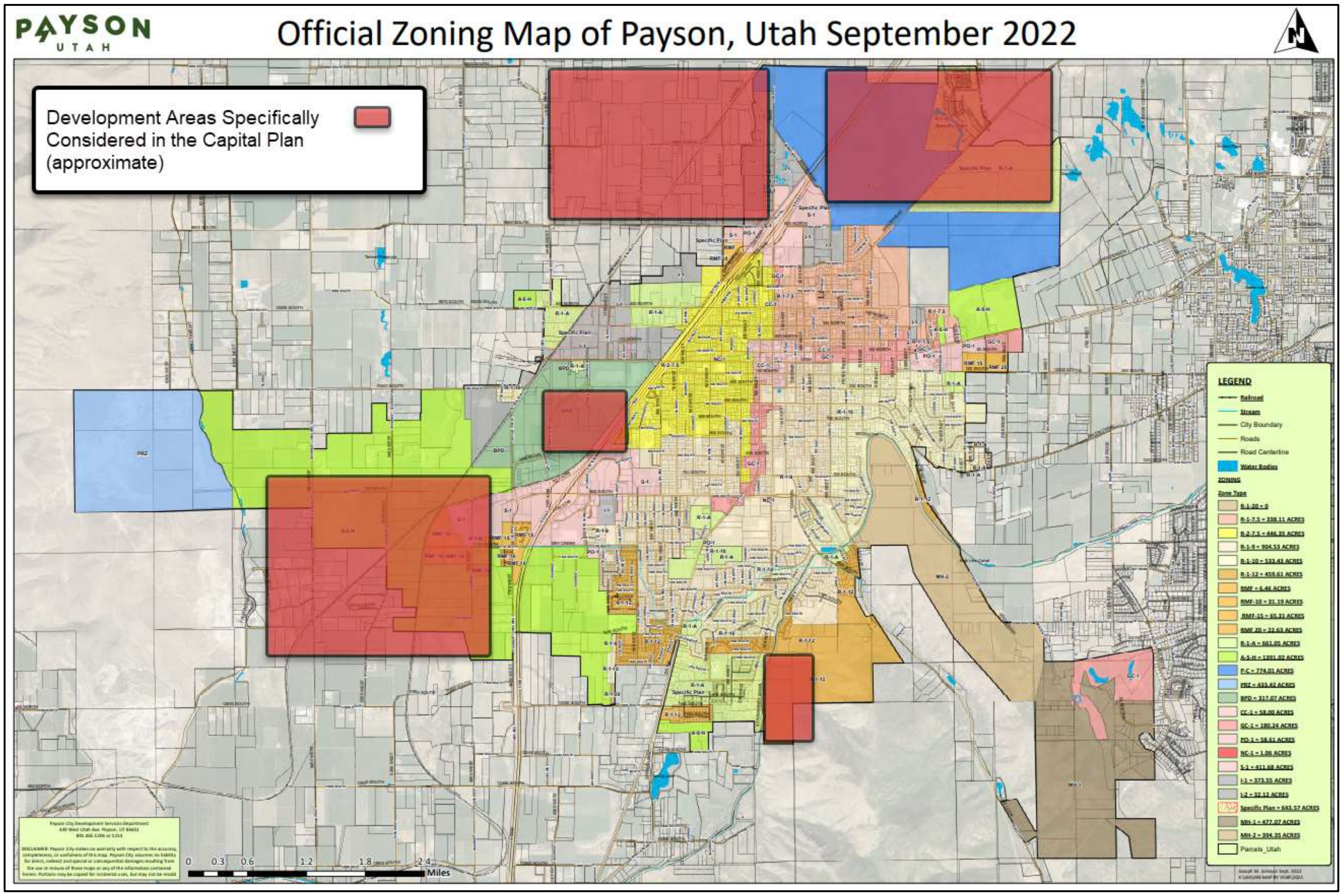


**Figure 4. Overlay of Development/Growth Areas on Zoning Map**

## 1.5 Development Area Load Estimate

In order to plan the capital expansion of the Payson City power system a development area load forecast was performed. Load forecasts were developed based on either the anticipated unit count or the acreage/space and type of use. Spatial load forecast was performed using the annexation, zoning, and proposed development information provided by the city. The maps (Figures 3 and 4) show where and what types of future development is anticipated. Development proposals and growth areas shown in Figure 4 were used to obtain a prediction of future electric demand in those specific areas.

Figure 5 shows the major proposed development area and the electrical load estimated for each. Table 1 shows the data that was used in the spatial load estimate. Appendix C shows the calculation basis that was used for estimating the load of the proposed large developments.

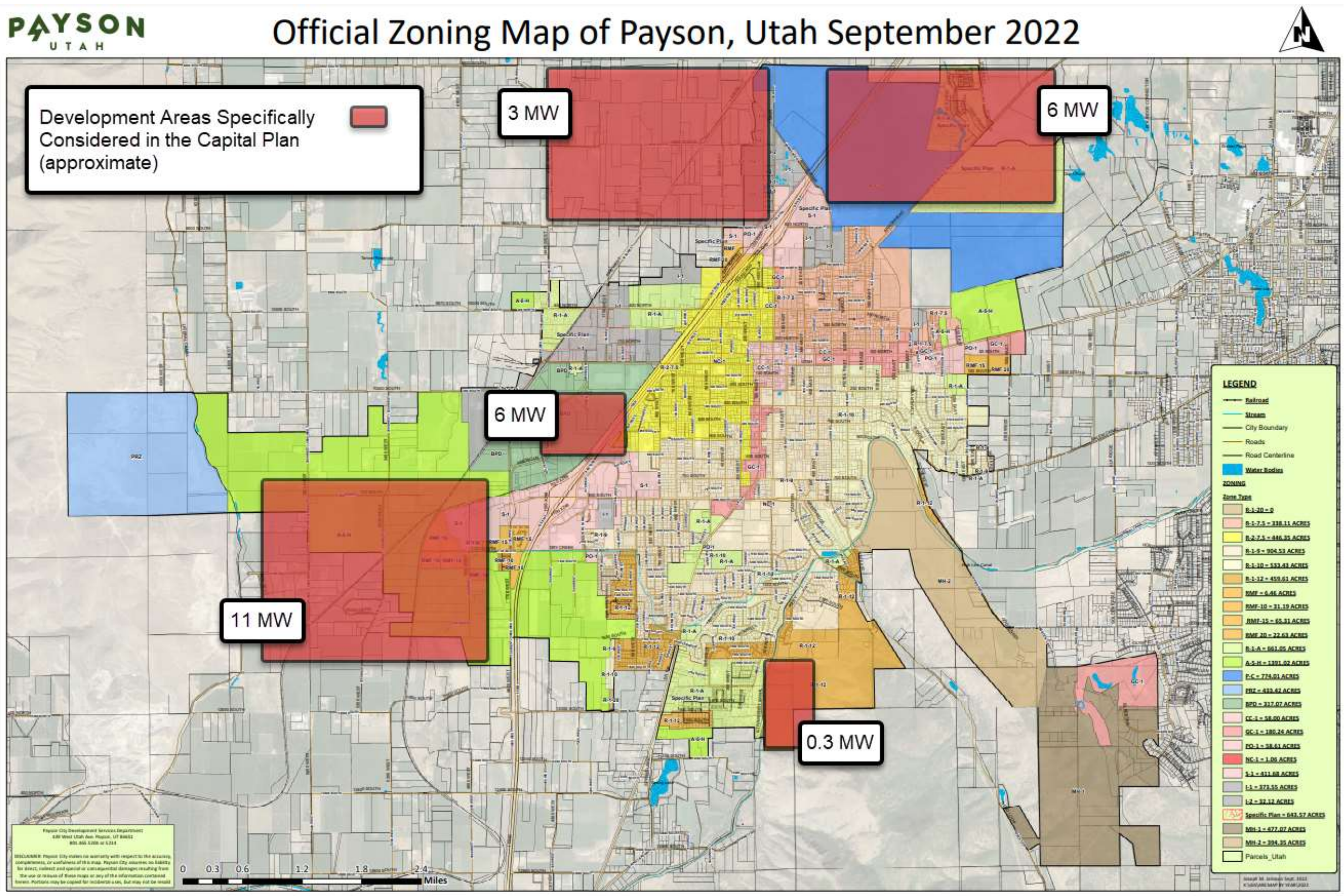


**Figure 5. Major Development Areas with Estimated Load**

**Table 1. Development Area Load Forecast**

| New Load | 2024-2029 Forecast Known/Proposed Additions Demand (MW) | 2030-2033 Forecast Known/Proposed Additions Demand (MW) |
|---|---|---|
| Northwest Payson | 1.5 | 1.5 |
| Arrowhead Trail Area | 6 | unknown |
| South | 0.3 | unknown |
| Southwest | 8 | 3 |
| Business Park | 4 | 2 |
| Total | 19.8 MW | 6.5 MW |

About 19.8 MW of the total spatial forecast demand will be used as the 2024-2029 spatial forecast load. The 2030-2033 spatial forecast demand of an additional 6.5 MVA is for the eventual development of these areas that may take longer than the 5-year period considered in this study.

The overall power demand forecast that considers this spatial load forecast is developed in Section 2.3. The full power demand forecast by feeder is provided in the Appendix B.

# 2. SYSTEM OVERVIEW

## 2.1 Existing Infrastructure

### 2.1.1 Supply

Payson City is a member of the Utah Associated Municipal Power Systems (UAMPS), an organization that allows each member to invest collectively in projects which benefit each specific member. Through UAMPS the city is able to participate along with other Municipalities in projects including wind, natural gas, hydroelectric, solar and geothermal generation.

Electric power is supplied to Payson City through the transmission substations and lines owned and maintained by Southern Utah Valley Power Systems (SUVPS) at 46 kV transmission voltage. This transmission system delivers power at Payson's Power Plant substation.

A map of the SUVPS power system is included as Figure 6. The city is located at the southernmost edge of the SUVPS system.

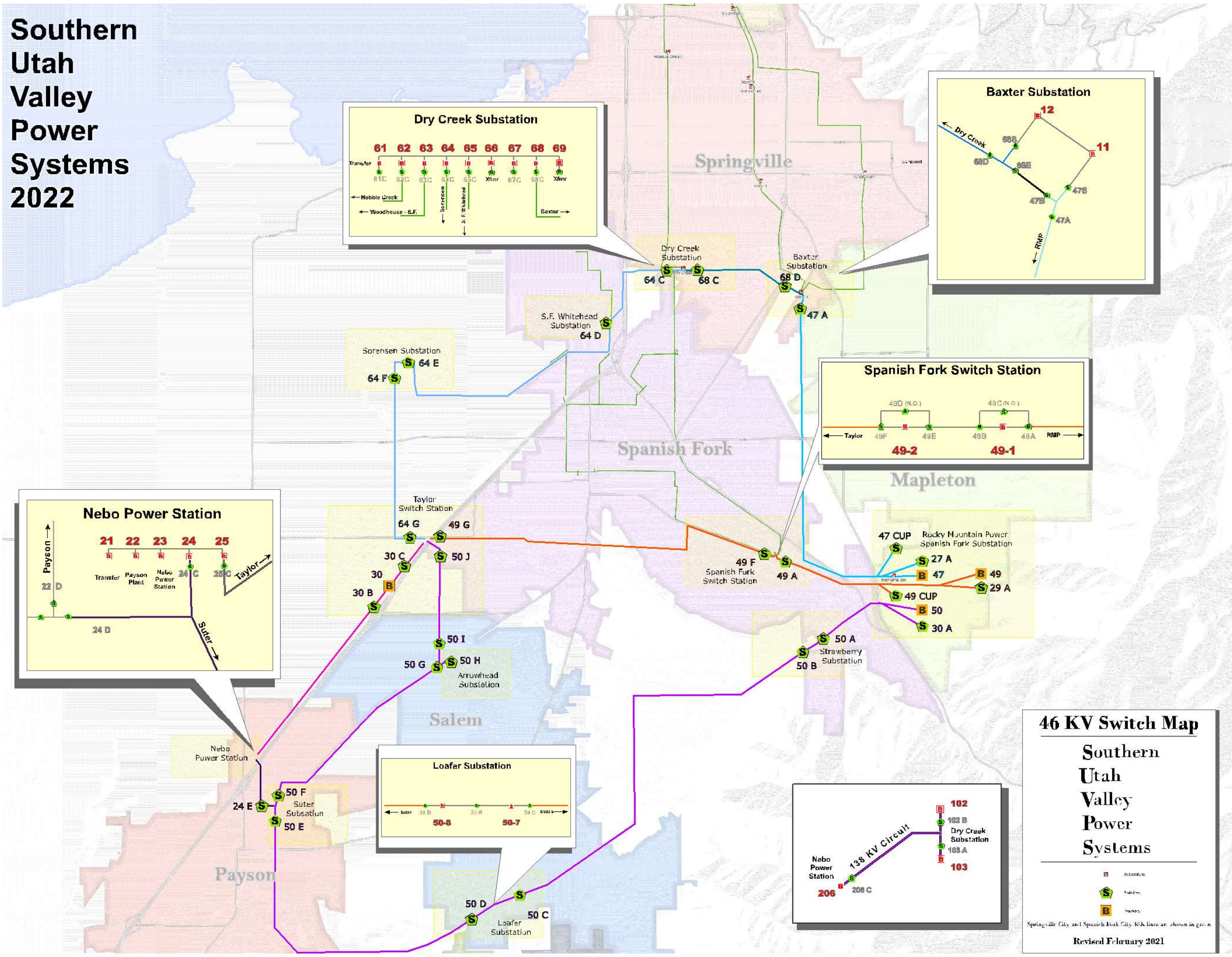


**Figure 6. SUVPS System Map**

Payson City owns five 46 kV-12.47 kV distribution substation transformers, two located at Industrial substation and one located in each other substation—Power Plant, Downtown and Racetrack substations.

The present total system substation transformer capacity is 49 MVA in normal operation. The distribution substations and their associated transformers, ratings, loading, and remaining capacities are listed in Table 2.

**Table 2. Existing Substation Transformers**

| Substation | Transformer | Base Rating--Capacity used for normal load (MVA) | Top Rating—Maximum Capacity used for "N-1" Contingency (MVA) | August 2023 Recorded Loading (MVA) | Remaining Transformer Capacity Available (MVA) |
|---|---|---|---|---|---|
| Downtown | T1 | 10 | 12 | 8.6 | 1.4 |
| Racetrack | T1 | 10 | 10 | 11.6 | -1.6 |
| Power Plant | T1 | 5 | 5 | 6.57 | -1.57 |
| Industrial | T1 | 12 | 20 | 3.9 | 8.1 |
| Industrial | T2 | 12 | 20 | 11.0 | 1.0 |
| | | | | | |
| Total | | 49 | | 41.67 | 7.33 |

### 2.1.2 Distribution System

From the Payson distribution substations there are twelve (12) 12.47/7.2 kV distribution feeders in service and two (2) spare feeders. Table 3 shows the recorded load on each of the active feeders in August 2023 and the remaining capacity available on each feeder.

These distribution feeders leaving the substations are generally constructed with 250 kcmil, 500 kcmil, or 1100 MCM aluminum (Al) underground cable, feeding 4/0 ACSR overhead conductor. The distribution feeders have rated capacity—270 to 450 amps (4.75 to 11.45 MVA). The ratings of the feeders are determined based on the limiting relay settings of the feeder protection. Rating limits are based on the conductor and the other equipment (e.g., reclosers, switchgear, elbows, bushings, connectors, etc.) in the main line of the system.

**Table 3 Payson Feeder Loads**

| Payson City Substations and 2023 Peak Demand | | | | | | | |
|---|---|---|---|---|---|---|---|
| Substation | Feeder # | Conductor Size | Relay Settings | Rated Feeder MVA | 2023 Feeder MW Peak | 2023 Feeder MVA Peak (Calculated) | Remaining Capacity Available |
| **Downtown Substation** | 310 | 250 MCM | 380 amps | 8.2 | 2.2 | 2.4 | 5.8 |
| | 320 | 250 MCM | 380 amps | 8.2 | 2.5 | 2.7 | 5.5 |
| | 330 | 250 MCM | 380 amps | 8.2 | 3.9 | 4.2 | 4 |
| | | | | | | | 0 |
| **Race Track Substation** | 410 | 500 MCM | 380 amps | 8.2 | 4.4 | 4.7 | 3.5 |
| | 420 | 500 MCM | 380 amps | 8.2 | 2.7 | 2.9 | 5.3 |
| | 430 | 500 MCM | 380 amps | 8.2 | 4.5 | 4.8 | 3.4 |
| | | | | | | | 0 |
| **Power Plant Distribution Substation** | 610 | 500 MCM | 270 amps | 5.8 | 3.45 | 3.7 | 2.1 |
| | 620 | 500 MCM | 270 amps | 5.8 | 3.12 | 3.3 | 2.5 |
| | | | | | | | 0 |
| | | | | | | | 0 |
| **Industrial Substation (two transformers)** | 510 | 500 MCM | 380 amps | 8.2 | 1.2 | 1.3 | 6.9 |
| | 520 | 500 MCM | 380 amps | 8.2 | 2.7 | 2.9 | 5.3 |
| | 530 | (Spare) | | | Spare (un used) | Spare (un used) | |
| | 710 | 1100 MCM | 450 amps | 9.7 | 2.8 | 3 | 6.7 |
| | 720 | (Spare) | | | Spare (un used) | Spare (un used) | |
| | 730 | 1100 MCM | 450 amps | 9.7 | 8.2 | 8.7 | 1 |
| | | | **Total Feeder Rated Capacity** | 96.6 MVA | **Total Remaining Capacity** | | 52 |

Conductors for the distribution delivery system are either located overhead on utility poles or buried underground. Distribution is normally three-phase in order to serve all types of customers; residential, commercial, and industrial.

## 2.2 Design Criteria (Level of Service Standards)

The city plans, designs and operates its system based on the following criteria:

- Transformer ratings under varying load levels and loading conditions must remain below their base rating;
- The system must be able to adequately serve load under single contingency (N-1) situations, where "N" is power system elements such as a transformer or line;
- The system switching required under an N-1 contingency should remain as simplified as possible to ensure that switching orders not become unnecessarily complex;
- Distribution circuit loading criteria must remain below 90% of the circuit's maximum current rating during normal operation;
- Primary circuit voltage must remain between 95% and 105% of its nominal value; and

- Distribution circuit main lines must be able to serve additional load under N-1 contingencies.

The above criteria were used to determine Payson's future facility needs based on the amount of load (i.e., demand) placed on the existing system over a pre-determined CFP/IFFP planning horizon (e.g., one, three, six and ten years). This ensures that there is sufficient reserve capacity built in the system to maintain service during the loss of a substation transformer or feeder during the peak load season.

The system voltage design criteria of the Payson City Power Department are to maintain voltage within a range of +/- 5% of nominal value in normal operation, and within a range of -10% to +5% of nominal value during short-term emergency operation. Table 4 lists these loading and voltage design criteria.

**Table 4. System Design Criteria (Level of Service)**

| **Element** | **Normal System** | **During Emergency ("N-1" Contingency)** |
|---|---|---|
| Substations transformer loading | 100% of Base Rating | 100% of Highest Nameplate Rating |
| Main line feeder Loading | 90% of the conductor rating | 100% of the conductor rating |
| Voltage | +/- 5% of nominal (0.95 p.u. to 1.05 p.u.) | + 5% to -10% of nominal (0.90 p.u. to 1.05 p.u.) |

**Table 5. Conductor Design Criteria Ratings**

| Conductor | Use | Design Criteria Rating, 90% (amps) | 100% Full Rating—Use during "N-1" Contingency Recovery (amps) |
|---|---|---|---|
| 1000 or 1100 kcmil Aluminum | Underground mainline | 540 amps | 600 amps |
| 500 kcmil Aluminum | Underground mainline | 346 amps | 385 amps |
| 250 kcmil Aluminum | Underground mainline | 229 amps | 255 amps |
| 4/0 URD Aluminum | Underground mainline | 207 amps | 230 amps |
| 477 kcmil ACSR | Overhead mainline | 540 amps | 600 amps |
| 4/0 ACSR | Overhead mainline | 306 amps | 340 amps |
| | | | |

Being able to continuously operate at an acceptable N-1 contingency level means that the system can withstand the loss of any single system component (equipment, transmission line, source, etc.) while still providing service to its customers at an acceptable standard of service as defined in Table 4. In order to verify that the city maintains N-1 contingency for its current system as well as for the future growth, the system model was modified to remove electrical components from service. Single contingency (N-1) analysis was conducted for individual substation transformers, and certain critical main lines.

As an example, if one of the substation transformers fails, the load being fed from that transformer must be fed from any of a combination of the remaining substation transformers. This load is transferred over to neighboring substation transformers by use of substation bus ties or distribution switches at the 12.47kV level. The transfer of this load from one transformer to its neighbors necessitates that both the neighboring transformers have enough available capacity to serve this additional load and that the distribution system is robust enough to support the transfer of the additional demand through the 12.47kV distribution system.

## 2.3 Peak Power Demand and Forecast

The coincident peak power demand of the Payson City power system was 33.793 megawatts (MW) in August 2023 (8/17/2023).

The Payson City historic peak power average growth rate is 2.7% per year over the seven-year period 2016 to 2023. Average typical load addition to the power system has historically been about 661 kW annually. The historic 2013-2021 peak power demand for Payson City—obtained from UAMPS annual reports—is shown on Figure 7, along with the projected peak power demand developed in this study for 2023-2032.

The projected peak shown on the chart shown in Figure 7 is calculated starting with the 2023 measured peak demand and applying a peak power demand growth rate of 1.24% annually, and the addition of estimated proposed loads of development through 2033 and the addition of 1.24% annual demand growth thereafter.

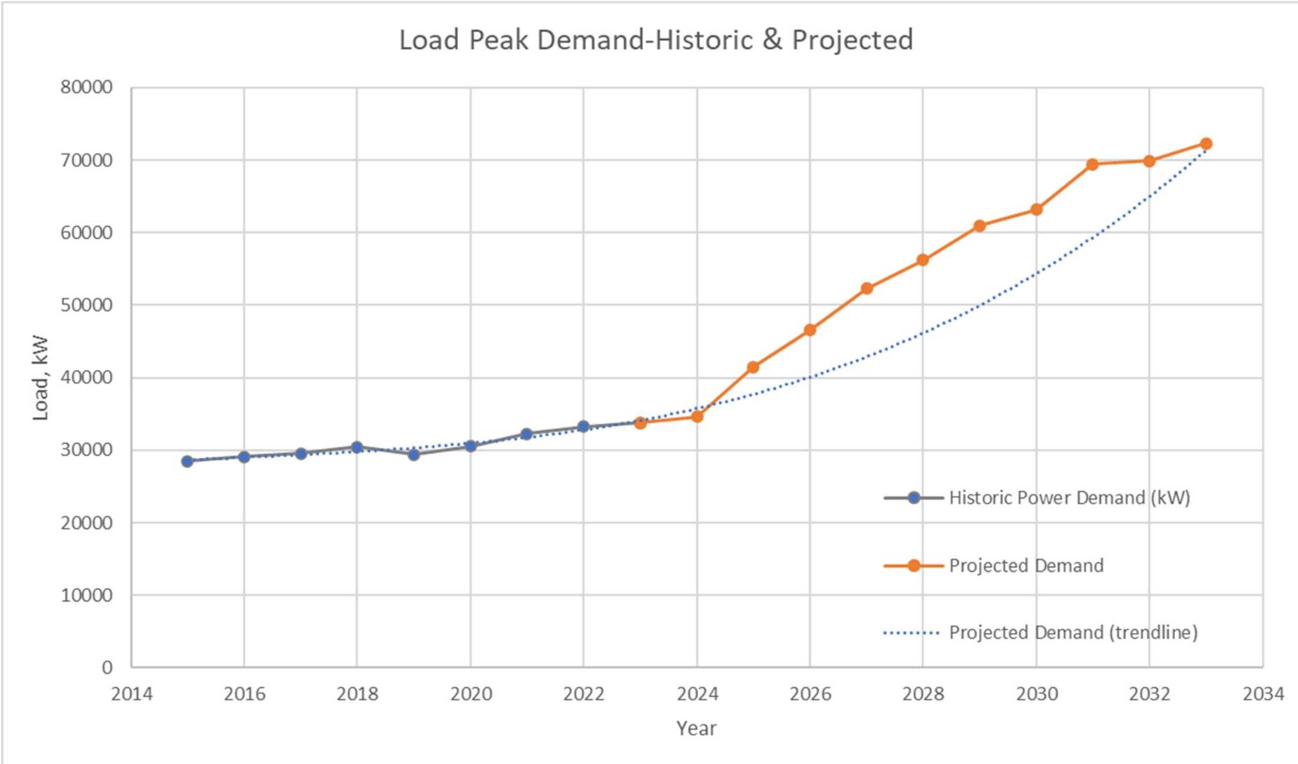


**Figure 2. Power Peak Demand Chart**

*NOTE: Historic loads were obtained from UAMPS annual reports*

Plans from developers that were mentioned in Sections 1.3 to 1.5 total an estimated load of about 26 MW. It is expected that the developer proposed new load will take 10 or more years before this full additional load will be seen on the system.

The known/proposed additions are combined with the normal demand growth forecast to estimate the total demand that could be expected. The results predict that about 16 to 26 MW will be added to the Payson Power system in the next 5 years.

The load forecast which was developed in cooperation with the Payson City Power Department for 2024 to 2033 at the substation level as shown in Table 6 was the load growth used in the study. The chart in Figure 7 and the load forecast in Table 6 reflect the estimates determined with the city power department. Table 6 shows the actual August 2023 and estimated 2024-2033 loading on the Payson substation transformers. A load forecast by feeder is in Appendix B.

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# Table 6. Payson City Load Forecast

**Payson Power**
**Load Forecast** — **Transformer Summary**

| 2023 | to | 2033 |
|---|---|---|

| Substation/Transformer | Growth Rate | Transformer Rating (MVA) | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | Utilization |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Industrial** | | 24 MVA | | | | | | | | | | | | |
| **Industrial-T1** | | 12 MVA | 4.20 | 4.29 | 9.39 | 11.13 | 11.38 | 11.44 | 11.49 | 11.55 | 11.60 | 11.66 | 11.72 | 98% |
| **Industrial-T2** | | 12 MVA | 11.70 | 11.85 | 9.86 | 10.01 | 10.55 | 10.89 | 11.05 | 11.20 | 11.36 | 11.52 | 11.68 | 97% |
| Industrial Sub Total | | MVA | 15.90 | 16.14 | 19.25 | 21.14 | 21.93 | 22.33 | 22.54 | 22.75 | 22.97 | 23.18 | 23.40 | |
| **Power Plant** | | 5 MVA | | | | | | | | | | | | |
| **Power Plant-T1** | | 5 MVA | 7.00 | 7.11 | 4.65 | 4.73 | 4.83 | 4.92 | 5.01 | 5.10 | 5.20 | 5.29 | 5.39 | 108% |
| Power Plant Sub Total | | MVA | 7.00 | 7.11 | 4.65 | 4.73 | 4.83 | 4.92 | 5.01 | 5.10 | 5.20 | 5.29 | 5.39 | |
| **Race Track** | | 10 MVA | | | | | | | | | | | | |
| **Race Track T1** | | 10 MVA | 12.40 | 12.60 | 11.48 | 11.63 | 10.87 | 11.03 | 11.19 | 11.36 | 11.52 | 11.69 | 11.87 | 119% |
| Race Track Sub Total | | MVA | 12.40 | 12.60 | 11.48 | 11.63 | 10.87 | 11.03 | 11.19 | 11.36 | 11.52 | 11.69 | 11.87 | |
| **Downtown** | | 10 MVA | | | | | | | | | | | | |
| **Downtown-T1** | | 10 MVA | 9.30 | 9.45 | 8.57 | 8.69 | 8.81 | 8.93 | 9.05 | 9.18 | 9.30 | 9.43 | 9.56 | 96% |
| Downtown Sub Total | | MVA | 9.30 | 9.45 | 8.57 | 8.69 | 8.81 | 8.93 | 9.05 | 9.18 | 9.30 | 9.43 | 9.56 | |
| **New North Arrowhead** | | 12 MVA | | | | | | | | | | | | |
| **Arrowhead North-T1** | | 12 MVA | 0.00 | 0.00 | 3.30 | 4.51 | 6.29 | 7.82 | 7.97 | 7.97 | 10.89 | 10.89 | 10.89 | 91% |
| Arrowhead North Sub Total | | MVA | 0.00 | 0.00 | 3.30 | 4.51 | 6.29 | 7.82 | 7.97 | 7.97 | 10.89 | 10.89 | 10.89 | |
| **New South** | | 12 MVA | | | | | | | | | | | | |
| **New South-T1** | | 12 MVA | 0.00 | 0.00 | 3.74 | 4.62 | 8.66 | 10.43 | 10.43 | 10.43 | 10.43 | 10.43 | 10.43 | 87% |
| New South Sub Total | | MVA | 0.00 | 0.00 | 3.74 | 4.62 | 8.66 | 10.43 | 10.43 | 10.43 | 10.43 | 10.43 | 10.43 | |
| **New West** | | 12 MVA | | | | | | | | | | | | |
| **New West-T1** | | 12 MVA | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 4.41 | 6.18 | 7.32 | 7.32 | 9.53 | 79% |
| New West Sub Total | | MVA | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 4.41 | 6.18 | 7.32 | 7.32 | 9.53 | |
| Grand Total | Forecast (Calculated, MVA) | | 44.6 | 45.3 | 51.0 | 55.3 | 61.4 | 65.5 | 70.6 | 73.0 | 77.6 | 78.2 | 81.1 MVA | |
| | Forecast (Calculated, MW @ 0.95 pf) | | 42.4 | 43.0 | 48.4 | 52.6 | 58.3 | 62.2 | 67.1 | 69.3 | 73.7 | 74.3 | 77.0 MW | |

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# 3. STUDY SUMMARY

## 3.1 System Modeling

The Payson City power system modeling was performed using the EasyPower 11.0 software application for electrical power system analysis. The model of the Payson power system was created in EasyPower and used in this capital facilities plans. It was developed using power system maps and field information.

The 2023 system peak was recorded in August 2023 for the Payson Power system. This load was used as the base in the system model at the beginning of the study period. The August 2023 peak load, system load measurements, and major customer connection points established in the model were used to allocate the load in the model on the system feeders. The power flow analysis was performed to evaluate the system compliance with the design criteria for the base year to identify any existing current (conductor overload) and voltage (bus low voltage) deficiencies. Known upcoming load additions and load growth corresponding to the map in Section 1.5 were then added to the system over the study period until known developments are completed, assumed in 2033. The power flow analysis was then run on the system model. The system voltage and current (transformer or conductor) deficiencies were identified for various periods of load growth at multi-year intervals until 2033.

The system model was studied in both normal operation and multiple “N-1” scenarios. Analysis of the system was performed under the “N-1” scenarios of the loss of each substation transformer to determine what system improvements were needed in order to restore and serve the customers while maintaining the emergency design criteria limits in Table 4. In a substation with two transformers, loss of one transformer or loss of one feeder at a time was studied in the analysis as the worst case. As various system components are removed from service in the system model the areas of deficiency caused by “N-1” contingencies can be identified. These are instances where the substation transformer or feeder loading exceeds the “emergency” design criteria of 100% rated capacity, or when voltage drops below 90% of nominal voltage. The top transformer rating, and 100% of the conductor rating are the design criteria limits used for “N-1” scenarios.

Projects were identified for accommodating the load growth and fixing the deficiencies that were identified. Tables 7 through 10 list the deficiencies identified in normal operation and in "N-1" contingencies.

## 3.2 Existing Deficiencies

The August 2023 recorded load on the Power Plant substation transformer appears to have been over the 5 MVA base rated loading design criteria. In addition, the Racetrack substation transformer appears to have been over the 10 MVA base rated loading design criteria in August 2023.

The loading of the Power Plant substation transformer can be resolved by switching to transfer load off the Power Plant feeders.

To reduce the load on the Racetrack substation transformer a new south substation will need to be built with feeders that take some load off Racetrack feeders.

**Table 7. Existing Deficiencies**

| Issue # | Element Over Design Criteria | Year (load level MW) | Loading (MVA or amps) | Percent of Rating (Design criteria is 90% for normal, 100% for "N-1") | Proposed Solution |
|---|---|---|---|---|---|
| 2023-1 | Power Plant substation transformer | 2023 (34 MW) | 7 MVA | 140% | Transfer load off feeders 610 and Power Plant substation, to feeder 510—Industrial substation transformer T1. |
| 2023-2 | Racetrack substation transformer | 2023 (34 MW) | 12.4 MVA | 124% | Transfer some load off of feeder 410, 430 and Racetrack substation, to feeder 710 and a new feeder from a new south substation. |

## 3.3 Growth Caused Deficiencies

When the proposed load from the planned commercial and residential developments, and the anticipated load growth are added to the system model the deficiencies caused by growth can be identified. Each time a system deficiency was identified a project was assigned and assumed to be implemented before the next analysis was run. The criteria given in Table 4 and Table 5 were used to determine deficiencies caused by load growth. The following tables list the deficiencies identified as system load is increased. The tables are divided into the projected years the deficiencies are predicted.

### 3.3.1 2025 Deficiencies

The system load in 2025 is forecast to be about 48 MW (51 MVA), while the capacity of the power system transformers is 49 MVA (the sum of the transformers base ratings). The system load in 2025 is forecast to be 104% of the capacity of the power system transformers, indicating the need for additional substation transformer capacity in the system. It is assumed for 2025 that the new south substation is installed as a solution for the Racetrack substation transformer overloading issue.

There are three deficiencies during normal operating conditions in 2025.

**Table 8. Deficiencies in 2025**

| Issue # | Element Over Design Criteria | Year (load level MW) | Loading (MVA or amps) | Percent of Rating (Design criteria is base rating, top rating for "N-1") | Proposed Solution |
|---|---|---|---|---|---|
| 2025-1 | Power Plant substation transformer | 2025 (48 MW) | 8.2 MVA | 164% | Build a new substation in the north near Arrowhead Trail to take about 3.2 MVA of the load off feeder 620 and Power Plant substation. |

| Issue # | Element Over Design Criteria | Year (load level MW) | Loading (MVA or amps) | Percent of Rating (Design criteria is base rating, top rating for "N-1") | Proposed Solution |
|---|---|---|---|---|---|
| 2025-2 | Industrial transformer T2 | 2025 (48 MW) | 13.23 MVA | 110% | Build tie between feeder 730 and 510 about 1700 W 800 S, to off-load some of feeder 730 load and Industrial transformer T2 |
| 2025-3 | Feeder 730 1100 MCM protective relay setting | 2025 (48 MW) | 450 amps | 100% | Raise the protective relay minimum trip setting, or transfer some load off feeder 730 with a tie between feeder 730 and 510 (solution of issue 2025-2) |

### 3.3.2 2027 Deficiencies

There are two related deficiencies during normal operating conditions in 2027 due to the growth in the southwest area of the system. Both issues have the same proposed solution—to move some load off feeder 510 to a new feeder from the new south substation.

The 2027 scenario assumes that the solutions to the 2025 issues have been implemented, specifically that a new south substation has been built.

**Table 9. Deficiencies in 2027**

| Issue # | Element Over Design Criteria | Year (load level MW) | Loading (MVA or amps) | Percent of Rating (Design criteria for sub transformer is 100% normal, 167% for "N-1") | Proposed Solution |
|---|---|---|---|---|---|
| 2027-1 | Industrial Substation Transformer T1 | 2027 (58 MW) | 14.8 MVA | 123% | Feed the new development in the Red Bridge area with a new line from the new South substation. |
| 2027-2 | Feeder 510 500 MCM | 2027 (58 MW) | 555 amps | 144% | Feed the new development in the Red Bridge area with a new line from the new South substation. |

### 3.3.3 2029 Deficiencies

There are two deficiencies in 2029 during normal operation.

**Table 10. Deficiencies in 2029**

| Issue # | Element Over Design Criteria | Year (load level MW) | Loading (MVA or amps) | Percent of Rating (Design criteria is 90% normal, 100% for "N-1") | Proposed Solution |
|---|---|---|---|---|---|
| 2029-1 | Downtown Substation Transformer T1 | 2029 (67 MW) | 10.12 MVA | 101% | Transfer some feeder 330 load (hospital/SR198) to a new feeder from the new substation in the north near Arrowhead Trail |
| 2029-2 | Feeder 510 500 MCM main line | 2029 (67 MW) | 398 amps | 103% | Reconductor mainline 500 MCM with 1100 MCM |

### 3.3.4 2033 Deficiencies

In 2030 the total system load is forecast at 73 MVA, the same at the substation transformer normal operation capacity (subject to the addition of substation transformers at Arrowhead and South substation). The total system load forecast is 81 MVA in 2033.

**Table 11. Deficiencies in 2033**

| **Issue #** | **Element Over Design Criteria** | **Year (load level MW)** | **Loading (MVA or amps)** | **Percent of Rating (Design criteria is 90% normal, 100% for "N-1")** | **Proposed Solution** |
|---|---|---|---|---|---|
| 2033-1 | System substation transformation capacity | 2033 (77 MW) | 81.1 MVA | 111% | In about 2030 add a new substation. A substation site in the southwest part of the system is assumed. |

## 3.4 "N-1" Contingency Deficiencies

When the system experiences the loss of a critical component (an "N-1" contingency condition) such as the loss of a substation transformer or feeder main line, the system must be able to be configured to restore service to the customers. The criteria given in Table 4 and Table 5 were used to determine deficiencies caused by "N-1" contingency conditions. The following tables list the "N-1" contingency condition deficiencies identified as system load is increased. The tables are divided into the projected years the "N-1" deficiencies are predicted. Each time a system deficiency was identified a project was assigned and assumed to be implemented before the next analysis was run.

### 3.4.1 Existing "N-1" Deficiencies

There appear to be about 12 issues that arise from N-1 losses of substation transformers at peak when other feeders are used to pick up the load normally carried.

**Table 12. Existing N-1 Deficiencies**

| Element Loss | Element Over Design Criteria | Year (load level MW) | Loading (MVA or amps) | Percent of Rating (Design criteria is 90% for normal, 100% for "N-1") | When Issues Occurs/Proposed Solution |
|---|---|---|---|---|---|
| Power Plant Sub | 310 Getaway 250 kcmil | 2023 (34 MW) | 266 amps | 104% | Using 330 to pick up 620 loads.<br>Build a new substation in the north near Arrowhead Trail to carry load upon the loss of the Power Plant sub transformer or feeder 620. |
| Downtown Sub | Power Plant Sub | 2023 (34 MW) | 8.2 MVA | 160% | Using 620 to pick up 330.<br>Build a new substation in the north near Arrowhead Trail to carry load upon the loss of the Downtown sub transformer or feeder 330. |
| Downtown Sub | Racetrack substation transformer | 2023 (34 MW) | 14.85 MVA | 145% | Using 410 to pick up 320.<br>Off load the Racetrack substation transformer with the new south substation feeder to make capacity for picking up the 320 feeder load and other Downtown substation load. |
| Downtown Sub | I-15 crossing 2/0 at 200 North | 2023 (34 MW) | 243 amps | 135% (of 180 amps) | Using I-15 crossing (610/510) fed from 510 to pick up 310.<br>Reconductor the 2/0 OH on 510/610 to feed 310 |

| Element Loss | Element Over Design Criteria | Year (load level MW) | Loading (MVA or amps) | Percent of Rating (Design criteria is 90% for normal, 100% for "N-1") | When Issues Occurs/Proposed Solution |
|---|---|---|---|---|---|
| Racetrack Sub | Downtown Substation transformer | 2023 (34 MW) | 12.1 MVA | 101% | Using 320 to pick up part of 420 and 330 to pick up part of 420.<br>Feed parts of 420 and 430 with the new south substation feeders. |
| Racetrack Sub | 320 Getaway 250 kcmil, And 4/0 ACSR 300 S 200 W | 2023 (34 MW) | 340 amps | 133% | Using 320 to pick up 410.<br>Reconductor 320 mainline. |
| Racetrack Sub | 330 Getaway 250 kcmil | 2023 (34 MW) | 316 amps | 124% | Using 330 to pick up 420.<br>Reconductor 4/0 Al UG on 500 E. Alternatively,<br>Feed parts of 420 with the new south substation feeders. |
| Racetrack Sub | 730 Getaway 1100 MCM | 2023 (34 MW) | 606 amps | 101% | Using 730 to pick up 430.<br>Feed parts of 430 with the new south substation feeders. |
| Racetrack Sub | 730 mainline 250 kcmil Al | 2023 (34 MW) | 366 amps | 144% | Using 730 to pick up 430.<br>Feed parts of 430 with the new south substation feeders. |
| Industrial Sub T1 510 feeder | 730 mainline 500 kcmil, 600 S | 2023 (34 MW) | 438 amps | 114% | Using 730 to pick up 510.<br>Is there switching to tie 710 to 510 for backup? |

| Element Loss | Element Over Design Criteria | Year (load level MW) | Loading (MVA or amps) | Percent of Rating (Design criteria is 90% for normal, 100% for "N-1") | When Issues Occurs/Proposed Solution |
|---|---|---|---|---|---|
| Industrial Sub T2 730 feeder | 510 mainline 500 kcmil, | 2023 (34 MW) | 460 amps | 119% | Using 510 to pick up 730. Feed parts of 730 with the new south substation feeders. |
| Loss of east 46 kV to Downtown and Racetrack | South Substation Transformer<br>Feeder 510 mainline 500 kcmil<br>Feeder 430 mainline fed from 830<br>Feeder 510 4/0 ACSR | 2023 (34 MW) | 21.5 MVA<br>484 amps<br>300 amps<br>426 amps | 108%<br>126%<br>130%<br>125% | Using remaining substations—Industrial and South (assumes South sub and a 46 kV loop) to pick up load from Downtown and Racetrack (about 20 MVA)<br>Build strong tie from 710 to 320 (100 South). Tie 840 to 410 from 1400 South to 800 South. Reconductor 510/610 I-15 crossing. |
| Loss of west 46 kV to Industrial Sub | South Substation Transformer<br>Downtown Substation Transformer<br>Feeder 320 mainline 500 kcmil<br>Feeder 430 mainline fed from 830<br>Feeder 510 4/0 ACSR | 2023 (34 MW) | 20.4 MVA<br>15.2 MVA<br>260 amps<br>300 amps<br>426 amps | 102%<br>127%<br>130%<br>125% | Using remaining substation to pick up load of Industrial (about 14 MVA)<br>Build Arrowhead substation to feed 330.<br>Build strong tie from 710 to 320 (100 South). Tie 840 to 410 to feed 730 from 1400 South to 800 South. Tie 810 to 510 to feed 510. |

### 3.4.2 Growth Caused "N-1" Deficiencies

The N-1 deficiencies caused due to growth from 2027 to 2029 are listed in the Tables 13 and 14 in this section. There appear to be about 14 issues that arise from N-1 losses of substation transformers and main feeders at peak when other feeders are used to pick up the load normally carried.

**Table 13. 2027 N-1 Deficiencies After new South substation, Arrowhead Sub, and other solutions**

| Element Loss | Element Over Design Criteria | Year (load level MW) | Loading (MVA or amps) | Percent of Rating (Design criteria is 90% for normal, 100% for "N-1") | Proposed Solution |
|---|---|---|---|---|---|
| Power Plant Sub | 510/610 2/0 OH | 2025-27 (48 MW) | 276 amps | 153% | Recond OH 2/0 610 from 510. 620 from Arrowhead feeder. |
| Downtown Sub | 730 mainline 500 kCMIL, 600 S to 800 S | 2027 (58 MW) | 509 amps<br>246 amps after solution | 132%<br>64% after | In picking up 320 from 730. Build 800 S to 1400 S tie to get South Sub Feeder to 800S. Or build strong tie from 710 to 320 on 100 South. |
| Downtown Sub | I-15 crossing 2/0 at 200 North | 2027 (58 MW) | 245 amps | 136% (of 180 amps)<br>72% of 4/0 ACSR | Using I-15 crossing (610/510) fed from 510 to pick up 310 (close at Payson Market.) Reconductor the 610/510 I-15 crossing. |
| Racetrack Sub | 730 mainline 500 kCMIL, 600 South to 800 South | 2027 (58 MW) | 454 amps<br>245 amps | 118%<br>64% | Using 730 to pick up 410. Build 800 S to 1400 S tie to get South Sub Feeder to 800 South. |

| Element Loss | Element Over Design Criteria | Year (load level MW) | Loading (MVA or amps) | Percent of Rating (Design criteria is 90% for normal, 100% for "N-1") | Proposed Solution |
|---|---|---|---|---|---|
| Racetrack Sub | 330 mainline 250 kcmil and 4/0 Al URD | 2027 (58 MW) | 302/299 amps<br><br>302/299 | 119%/130%<br><br>78%/78% of 500 kCMIL | Using 330 to pick up most of 420.<br>Reconductor 250 kcmil UG getaway and 4/0 AL UG on 500 E. Or, switches to feed part of 420 from 320, then the 4/0 Al URD overloads. |
| South Sub | 510 mainline 500 kcmil<br><br>4/0 ACSR mainline | 2027 (58 MW) | 552 amps<br><br>382 amps | 143%<br>92% of 600 amp 1100 MCM<br>112% of 340 amps | Using 510 to pick up 810 |
| South Sub | 730 500 kcmil mainline | 2027 (58 MW) | 496 amps | 128%<br><br>83% of 600 amp 1100 MCM | Using 730 to pick up 810 part and 840 |
| Arrowhead Sub | Downtown Substation Transformer<br><br>Feeder 330 mainline 250 kcmil, 2/0 Cu, and 4/0 URD and | 2027 (58 MW) | 15.1 MVA<br><br>442 amps | 126%<br><br>173% | Using 330 to pick up Arrowhead Substation load.<br>Build strong tie from 710 to 320 (100 South) and feed part of 320 load, making room for Arrowhead loads on the Downtown Sub Transformer. Reconductor 330 mainline to feed Arrowhead loads. |

**Table 14. 2029 N-1 Deficiencies After new South substation, Arrowhead Sub, and other solutions**

| Element Loss | Element Over Design Criteria | Year (load level MW) | Loading (MVA or amps) | Percent of Rating (Design criteria is 90% for normal, 100% for "N-1") | Proposed Solution |
|---|---|---|---|---|---|
| Downtown Sub | 510 mainline 500 kCMIL, | 2029 (67 MW) | 430 amps | 112%<br><br>72% of 1100 MCM | In picking up 320 from 810 requires transfer to 510 (So trans sub is 23 MVA). Recond 510 mainline to 1100 MCM. Or build strong tie from 710 to 320 (100 South) and feed 320 load from 710 (shifts 3 MVA from 840 to 710). |
| South Sub | Industrial Substation T2 | 2029 (67 MW) | 24.8 MVA | 124% | 7 MVA of load on 810 overloads Industrial Substation T2. Requires new substation in the southwest area to back up the South substation. |
| South Sub | 510 mainline 1100 MCM<br>510 4/0 ACSR | 2029 (67 MW) | 653 amps<br><br>484 amps | 116%<br><br>142% | Using 510 to pick up 810 Move I-15 Crossing of 510 to 310. |
| South Sub | 730 500 kcmil mainline | 2029 (67 MW) | 582 amps | 150% | Using 730 to pick up 810 part and 840. Build new I-15 crossing of new 720 feeder from business park to 800 South 1000 West, pick up some load from 730. |

| Element Loss | Element Over Design Criteria | Year (load level MW) | Loading (MVA or amps) | Percent of Rating (Design criteria is 90% for normal, 100% for "N-1") | Proposed Solution |
|---|---|---|---|---|---|
| Arrowhead Sub | Downtown Substation Transformer<br><br>Feeder 330 mainline 250 kcmil, 2/0 Cu, and 4/0 URD and | 2029 (67 MW) | 16.5 MVA<br><br>583 amps | 138%<br><br>229% | Using 330 to pick up Arrowhead Substation load. Build new North substation to backup Arrowhead sub transformer loss |
| Feeder 730 | Feeder 510 mainline 500 kcmil | 2029 (67 MW) | 466 amps | 121% | Using 510 to pick up 730 |
| | | | | | |

# 4. CAPITAL PLAN PROJECTS

This section lists all the capital projects included in the Payson City Capital Projects Plan. Fifteen projects are identified in Table 15 to resolve the issues listed in Tables 7-14 that come up from analysis of the current system and load, and analysis of the system model and forecast load. Additional capital projects identified by the Payson City Power department are listed also in Table 16. In addition, SUVPS transmission system capital projects for which Payson City is required to participate financially are listed in this section.

The opinion of probable cost for all projects does not include the cost of easements that might be needed.

## 4.1 Projects Identified by Power System Analysis

**Table 15. Capital Plan Project List from System Analysis**

| Project # | Project Title | Project Description | Operation Improvement Result |
|---|---|---|---|
| 1 | Switch 610 to 510 | In 2024, switch/install 3-phase overhead switch about 300 North, to transfer part of 610 load to 510. | Issue: 2023-1. 7 MVA on Power Plant Transformer (5 MVA rating).<br>Benefit: Reduce loading of Power Plant Transformer to 3.7 MVA |
| 2 | Build South Substation, Transmission line and Feeders | In 2024, build South substation with 12/20 MVA transformer and four feeders. Build 46 kV transmission line 1.65 miles from Racetrack sub to new sub site. | Issue: 2023-2. 12 MVA on Racetrack Transformer (10 MVA rating).<br>Benefit: Reduce loading of Racetrack Transformer to 8.5 MVA. New substation provides "N-1" contingency backup/recovery for the loss of Downtown or Racetrack subs. |
| 3 | Build North/Arrowhead Substation, Transmission line and Feeders | In 2025, build North/Arrowhead substation with 12/20 MVA transformer and four feeders. Build 46 kV transmission tap 0.5 miles off Power Plant-Downtown 46 kV line to new sub site. | Issue: 2025-1. 8.2 MVA on Power Plant substation transformer (5 MVA rating).<br>Benefit: Reduce loading of Power Plant Transformer to 4.7 MVA. New substation provides "N-1" contingency backup/recovery for the loss of Power Plant or Downtown subs. Operational flexibility for normal and N-1 conditions. |
| 4 | Strong Tie Feeders 510 to 730 | In 2025, build tie between feeder 730 and 510 about 1700 West 800 South, with switches as needed. | Issue: 2025-2 & 3. 13.2 MVA on Industrial substation transformer T2 (12 MVA rating).<br>Benefit: Reduce loading of T2 transformer to 10 MVA. Operational flexibility for normal and N-1 conditions. |
| 5 | Rebuild/reconductor Feeder 510/610 I-15 crossing | In 2024, Reconductor/rebuild the 510/610 I-15 crossing about 200 North with about 0.4 miles (2,100 ft) with 260-amp capacity (min.) conductor. | Issue: 2023 "N-1" loss of Downtown, restoring feeder 310. #2/0 Al conductor loads to 248 amps (180 amp rating).<br>Benefit: A strong tie between 310 and 510 crossing I-15. Operational flexibility for normal and N-1 conditions. |
| 6 | South substation feeder tie to 800 South along SR-198/500 West | In 2024, build South substation a feeder about 1.4 miles (7,350 ft) with 250-amp capacity (min.) conductor | Issue: 2023 "N-1" loss of Racetrack, restoring feeder 410, feeder 320 250 kcmil UG conductor loads to 349 amps (255 amp rating).<br>Benefit: A strong tie between South substation and 410. Operational flexibility for normal and N-1 conditions. |
| 7 | Strong Tie Feeders 710 to 320 | In 2024, build strong tie from 710 to 320, from 1000 West Utah Ave. to 200 West 100 South, about 0.83 miles (4,400 ft) with 200-amp capacity (min.) conductor. | Issue: 2023 "N-1" loss of 46 kV transmission line to Downtown and Racetrack, restoring feeder 320, South substation transformer goes to 21.5 MVA (20 MVA rating).<br>Benefit: A strong tie between Industrial substation and Downtown. Operational flexibility for normal and N-1 conditions. |

| Project # | Project Title | Project Description | Operation Improvement Result |
|---|---|---|---|
| 8 | 46 kV Transmission Loop to South substation | In 2025, build 46 kV transmission from Industrial substation to the South substation, about 3.6 miles (19,100 ft) with 795 ACSR conductor. | Issue: 2023 "N-1" loss of 46 kV transmission line to Downtown and Racetrack, restoring from South substation transformer requires a loop feed to South substation. Industrial substation transformers do not have combined available capacity enough (20 MVA available capacity) for picking up 26 MVA of load. Benefit: A 46 kV transmission loop, with appropriate 46 kV switches enables restoring substations for outage on sections of lines between substations. Operational flexibility for normal and N-1 conditions. |
| 9 | South substation feeder 810 tie to 510/730 (along 12000 South 4600 West, county) | In 2027 (for "N-0", in 2024 for "N-1", build a South substation feeder 810 to feeder 510/730 at 1700 West 1200 South about 2 miles (10,500 ft) with 600-amp (250-amp min.) capacity conductor (along 12000 South 4600 West, county). | Issue: 2027-1 and 2027-2 "N-0" and 2023 "N-1" loss of Industrial T1, restoring feeder 510, feeder 730 500 kcmil UG conductor loads to 438 amps (385 amp rating). Benefit: A strong tie between South substation and 510. Operational flexibility for normal and N-1 conditions. |
| 10 | Reconductor/rebuild 330 Mainline | In 2027, reconductor/rebuild feeder 330 getaway and mainline on Utah Ave. and 500 East about 0.14 miles (750 ft) to 440-amp capacity (min.) conductor | Issue: 2027 "N-1" loss of Racetrack substation or Arrowhead substation, restoring feeder 420 or Arrowhead feeder, feeder 330 250 kcmil UG conductor loads to 303 amps (255 amp rating). Benefit: A higher capacity getaway and mainline on 330. Operational flexibility for normal and N-1 conditions. |
| 11 | Strong Tie Feeders Arrowhead 920 to 330 | In 2029, build tie between 920 (from Arrowhead) to 330 with 340-amp capacity (min.) conductor along 700 East about 1 mile (5,150 ft) along 750/900 East to SR-198 (tie to 330). | Issue: 2029-1. 10.12 MVA on Downtown transformer (10 MVA rating). Benefit: A strong tie between Arrowhead and Downtown substations. Operational flexibility for normal and N-1 conditions. |
| 12 | Reconductor/rebuild 510 Mainline | In 2029 (for "N-0", in 2027 for "N-1", Reconductor 510 mainline 500 MCM with 1100 MCM and 4/0 ACSR with 477 ACSR about 1.7 miles (8,850 ft) from Industrial substation to 1700 West 1200 South (tie to feeder 810) | Issue: 2029-2 "N-0" and 2027 "N-1" loss of South substation, restoring feeder 810, feeder 510 500 kcmil UG conductor and 4/0 ASCR loads to 552 amps (385 amp rating) and 382 amps (340 amp rating on 4/0 ACSR). Benefit: A strong tie between South substation and 510. Operational flexibility for normal and N-1 conditions. |
| 13 | Reconductor/rebuild 730 Mainline | In 2029 (for "N-0", in 2027 for "N-1"), Reconductor 730 mainline underground conductor about 0.9 miles (4,800 ft) with 1100 MCM from 500 S American Way to 1700 West 1200 South (tie to feeder 810). | Issue: 2029-2 "N-0" and 2027 "N-1" loss of South substation, restoring feeders 810 and 840, feeder 730 UG conductors load to 460-496 amps (330-385 amp ratings). Benefit: A strong tie between South substation and 730. Operational flexibility for normal and N-1 conditions. |

| Project # | Project Title | Project Description | Operation Improvement Result |
|---|---|---|---|
| 14 | Build Southwest area Substation and Feeders | In 2033 (for "N-0", in 2029 for "N-1"), 2029, build Southwest area substation with 12/20 MVA transformer and four feeders. Build 46 kV transmission tap 0.5 miles off Industrial-South sub 46 kV line to new sub site. | Issue: 2033 "N-0" system substation loading goes to 81.1 MVA (total "N-0" capacity 73 MVA). Also, 2029 "N-1" loss of South substation, loads Industrial substation transformer T2 to 24.8 MVA (20 MVA rating). Benefit: New substation capacity becomes available in the southwest area for new growth there. Operational flexibility for normal and N-1 conditions. |
| 15 | Build new North area Substation and Feeders | In 2029, build North area substation with 12/20 MVA transformer and four feeders. Build 46 kV transmission tap 0.5 miles off Power Plant-Downtown 46 kV line to new sub site. | Issue: 2029 "N-1" loss of Arrowhead substation, loads Downtown substation transformer to 16.5 MVA (12 MVA rating). Benefit: New substation capacity becomes available in the north area for new growth there. Operational flexibility for normal and N-1 conditions. |

## 4.2 Payson City Identified Capital Projects

The Payson City Power Department identified the capital projects listed in Table 16. These are projects that were specifically included in this report for completeness though they did not arise from the system modeling and analysis like the projects identified in Section 3.

**Table 16. Payson City Power Project List**

| Project # | Project Title | Project Description | Operation Improvement Result |
|---|---|---|---|
| Payson-1 | Peaking Generation Capacity—new 14.4 MW | Install new peaking generation capacity—six 2.4 MW gensets with generation building and substation. | Issue: Forecast loads will increase the amount of energy Payson will need to supply, by purchase or generation, during peak use periods. Benefit: New generation capacity to serve existing and new load provides operational flexibility for normal and peak use periods. |
| Payson-2 | System Model, with linked OMS and Dispatch | Develop a Power System Model (such as using Mil Soft software) and link to a software system for OMS, and Dispatch. | Issue: Growth of the power system in size and complexity decreases system awareness, increases outage response time. Benefit: Increased system awareness for management and operations. Speeds outage response time. Provides means for rapid switching orders. |

## 4.3 SUVPS Identified Capital Transmission Projects

Payson City relies upon SUVPS to serve the Payson substations through the SUVPS 46 kV transmission system. SUVPS owns, maintains, and upgrades portions of the 46 kV system. Capital projects on the SUVPS system are identified by SUVPS with its customers (e.g., Payson City Power, and other customer cities) and through system modeling and analysis. These projects are primarily driven by growth in demand of the cities, like Payson, that are served by the SUVPS 46 kV transmission system. The projects listed in Appendix E are the SUVPS Capital Transmission Projects that Payson City, as a member city, is obligated to financially participate in. The bond obligation for these SUVPS projects is shown on Table 18.

**Table 17. SUVPS Capital Projects**

| Project # | Project Title | Project Location—Approx. Address | Project Description | Operation Improvement Result |
|---|---|---|---|---|
| SUVPS-1 | SUVPS 46 kV Transmission System Capital Projects | Various | $40,000,000 to $50,000,000 Bond<br>$2,860,000 Bond payment per year.<br><br>Payson portion:<br>$446,732 per year. | 46 kV transmission capacity to serve growing load in member cities.<br><br>Capability to continue 46 kV service upon “N-1” contingency recovery. |

SUVPS anticipates obtaining a $40-$50 million bond to pay for the proposed SUVPS projects. The proposed bond period is 20 years, each SUPVS member’s payment per year will be based on their usage of the system. The following is the preliminary high-level estimate of the Payson City obligation for bond payments for 2024 through 2028. The actual costs will be firmed up when the bond is obtained.

The SUVPS $50 million bond payment is $2,750,000.00 per year. Payson’s projected payment obligation is based on their percent usage of the capacity on the SUVPS system, as follows:

2024 – 15.62% usage corresponds to $446,732.00 payment

2025 – 15.62% usage corresponds to $446,732.00 payment

2026 – 15.62% usage corresponds to $446,732.00 payment

2027 – 15.62% usage corresponds to $446,732.00 payment

2028 – 15.62% usage corresponds to $446,732.00 payment

For 2028 to 2032 consider that the projected annual payment obligation will be $446,732.00.

These numbers are all high-level estimates that will be firmed up after the bond amount, payment period and interest is confirmed when the bond is secured. The MVA ownership adjustment cost will be firmed up in October 2024 when actual usage, cost etc. are known.

# 5. CAPITAL PROJECTS SUMMARY

This section lists projects that were identified by analysis as being necessary over the planning window. It also lists the projects identified by the prior IFFP, by Payson City and SUVPS. These projects were broken down into five priority levels; High Priority, Moderately High Priority, Medium Priority and Low Priority, each level corresponds to a different implementation schedule. The physical location of future development was modeled as realistically as possible, however due to unpredictability of load growth in both scale and the location some projects may need to be implemented prior to the scheduled dates below and some can be postponed.

Project Priority Levels:

High Priority – Recommended to be completed within one year

Moderately High Priority- Recommended to be completed within three years

Medium Priority- Recommended to be completed within five years

Low Priority- Recommended to be completed within ten years

Projects to resolve the deficiencies identified in the study of the system model were identified and developed. The system improvement projects necessary due to growth were determined in this study are listed in Table 15, shown in Table 18, and details are provided in Appendix A of this report. Payson City Power projects and SUVPS system projects from Tables 16 and 17 are also included in Table 18.

The opinion of probable cost for all projects does not include the cost of easements that might be needed.

**Table 18. Capital Projects List**

| Project # & Title | Implementation Year(s) Load Level, MW | Opinion of probable Cost ('24 $) | Construct year prob. Cost |
|---|---|---|---|
| **High Priority** | | | |
| 1. Switch 610 to 510 | 2024<br>34 MW | $15,600 | $15,600 |
| 2. Build South Substation, Transmission line and Feeders | 2024<br>34 MW | $8,367,500 | $8,367,500 |
| 3. Build North/Arrowhead Sub, Transmission line, feeders | 2025<br>48 MW | $6,250,300 | $6,250,300 |
| 4. Strong Tie Feeders 510 to 730 | 2025<br>48 MW | $205,300 | $205,300 |
| 5. Rebuild/reconductor Feeder 510/610 I-15 crossing | 2024<br>34 MW | $74,400 | $74,400 |
| 6. South sub feeder tie to 800 South along SR-198/500 W | 2024<br>34 MW | $244,100 | $244,100 |
| 7. Strong Tie Feeders 710 to 320 | 2024<br>34 MW | $368,500 | $368,500 |
| 8. 46 kV Transmission Loop to South substation | 2025<br>48 MW | $2,448,700 | $2,448,700 |
| 9. South substation feeder 810 tie to 510/730 | 2024<br>34 MW | $628,000 | $628,000 |
| | | | |
| **Moderately High Priority** | | | |
| Payson-1 Peaking Generation Capacity—new 14.4 MW | 2024<br>34 MW | $33,000,000 | $33,000,000 |
| 10. Reconductor/rebuild 330 Mainline | 2027<br>58 MW | $328,800 | $369,900 |
| 11. Reconductor/rebuild 510 Mainline | 2027<br>58 MW | $316,300 | $355,800 |
| 12. Reconductor/rebuild 730 Mainline | 2027<br>58 MW | $544,500 | $612,500 |
| | | | |
| **Medium Priority** | | | |
| 13. Strong Tie Feeders Arrowhead 920 to 330 | 2029<br>67 MW | $408,100 | $496,600 |
| 14. Build Southwest area Substation and Feeders | 2029<br>67 MW | $6,250,300 | $7,604,500 |
| 15. Build new North area Substation and Feeders | 2029<br>67 MW | $6,250,300 | $7,604,500 |
| | | | |
| **Low Priority** | | | |
| Payson-2 System Model, with linked OMS and Dispatch | 2033<br>77 MW | $433,000 | $641,000 |
| **Bond Obligation** | | | |
| SUVPS-1. Transmission System Capital Projects | 2024-2033<br>34-77 MW | $4,467,320 | $4,467,320 |
| **Total** | | **$70,601,020** | **$73,754,520** |

The opinion of probable cost for these projects is in 2023 dollars. The opinion of probable cost for all projects does not include the cost of easements that might be needed.

As with most capital facilities plans, most of these projects are scheduled to occur in the earlier planning windows. However, growth in demand on the system generally happens in “groups” or “lumps” according to actual commercial and residential development. Some of the projects which were identified could be delayed until required by localized growth.

## 6. CONCLUSION

This study identifies 17 capital improvement projects and the SUVPS bond obligation that are recommended to continue to meet the needs of the Payson City electrical power system during the period 2024-2033. The projects are the result of analyzing the existing Payson City power system for its current capacity and analyzing the system under anticipated load growth and identifying deficiencies and solutions. The power flow analysis was performed on the Payson City power system model to evaluate the system compliance with the design criteria and to identify system capacity deficiencies at periods of 1 year, 3 years, 5 years, then at 10 years out. Projects included in this 2024-2029 5-Year Capital Plan are solutions that provide the system capacity needed for Payson City to serve its customers, that prevent system voltage and loading problems, and that provide for contingency operation.

# 7. APPENDIX A: PROJECT DETAIL SHEETS

Project detail sheets are included for the projects from Section 4. Project detail sheets are not included for the projects that were identified by Payson Power in Section 4.2, or for the SUVPS listed projects in Section 4.3.

The opinion of probable cost for projects does not include the cost of easements that might be needed.

| Project # : 1 | Project Title: Switch 610 to 510 | Priority: High – 1 Year<br>Load Level 34 MW |
|---|---|---|

**Project Description:** Switch/install 3-phase overhead switch about 300 North 500 West, to transfer part of feeder 610 load to feeder 510.

**Issue(s):** 1) In 2023, 7 MVA on Power Plant Transformer (5 MVA rating).

**Design Criteria Violation:**

| Element | Normal or "N-1" | Measured or Modeled Value | Design Criteria Value |
|---|---|---|---|
| Power Plant Transformer | Normal | 7 MVA (measured)<br>140% of rated capacity | 5 MVA<br>100% rated capacity |

**Benefit(s) of Project**: Reduce loading of Power Plant Transformer to 3.7 MVA, typically results in longer transformer life.

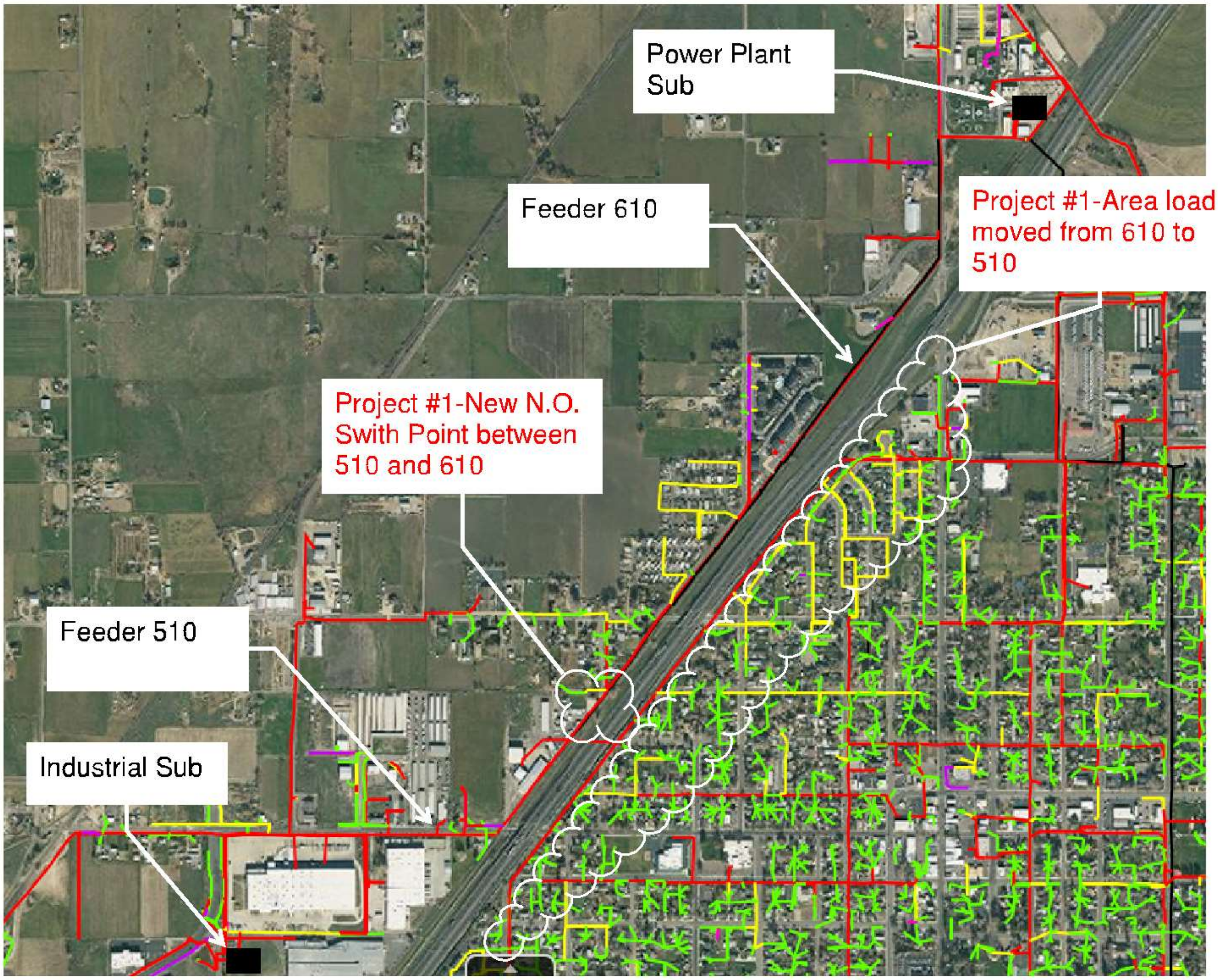
| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| Power Plant Transformer | Normal | 3.7 MVA<br>74% of rated capacity | 5 MVA<br>100% rated capacity |

**Opinion of Probable Cost:** $5,000

**Risk Assessment:** High normal loading on this 46 kV-12.47 kV transformer during peak periods leads to limitations serving the growing load and restoring outages on the system. With loading greater than the transformer rating for longer periods of time and more frequently the likelihood of transformer failure increases. Higher customer outage time and lower system resiliency are at risk.

**Alternatives Considered:** 1.) Replace the Power Plant substation transformer with a 10 MVA or larger transformer. The cost of the alternative is higher than switching to reduce the load on the existing transformer.

**Project #1 Map**



| Project # : 2 | Project Title: Build South Substation, Transmission line and Feeders | Priority: High – 1 Year Load Level 34 MW |
|---|---|---|

**Project Description:** Build South substation with 12/20 MVA transformer and four feeders. Build 46 kV transmission line 1.65 miles from Racetrack sub to new sub site.

**Issue(s):** 1) 12 MVA on Racetrack Transformer (10 MVA rating)

**Design Criteria Violation:**

| Element | Normal or "N-1" | Measured or Modeled Value | Design Criteria Value |
|---|---|---|---|
| Racetrack Substation Transformer | Normal | 12 MVA (measured) 120% of rated value | 10 MVA 100% of rated capacity |

**Benefit(s) of Project**: Reduce loading of Racetrack Transformer to 8.5 MVA. New South substation provides "N-1" contingency backup/recovery for the loss of Downtown or Racetrack subs.

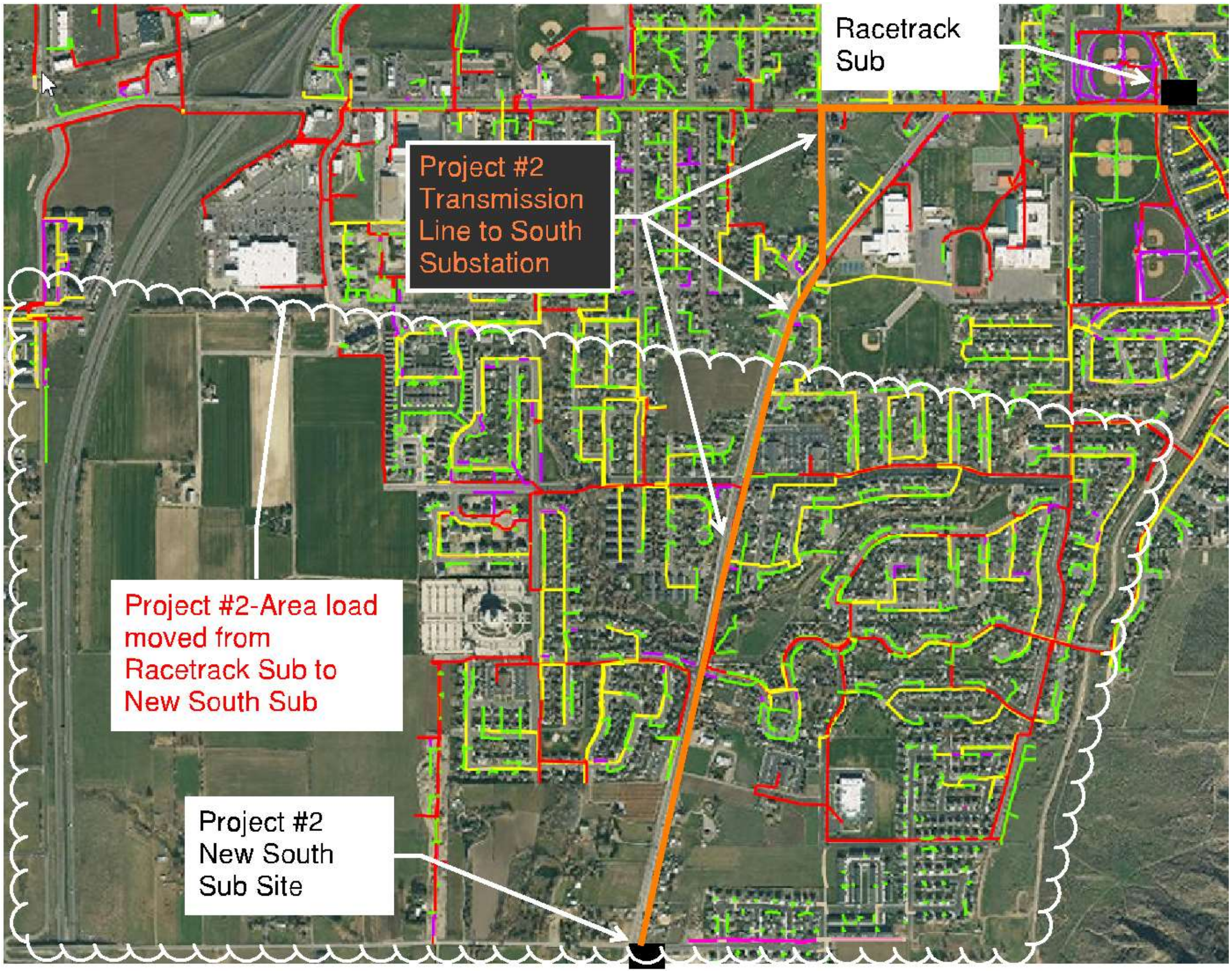
| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| Racetrack Substation Transformer | Normal | 8.5 MVA (modeled) 85% of design value | 10 MVA 100% of rated capacity |

**Opinion of Probable Cost:** $8,367,500 (does not include easements)

**Risk Assessment:** High normal loading on this 46 kV-12.47 kV transformer during peak periods leads to limitations serving the growing load and restoring outages on the system. With loading greater than the transformer rating for longer periods of time and more frequently the likelihood of transformer failure increases. Higher customer outage time and lower system resiliency are at risk.

**Alternatives Considered:** 1.) Replace the Racetrack substation transformer with a 12/20 MVA transformer. The alternative does not mitigate the "N-1" loss of the substation transformer with another substation transformer to pick up the load of the lost transformer.

**Project #2 Map**



| Project # : 3 | **Project Title:** Build North/Arrowhead Substation, Transmission line and Feeders | **Priority:** High – 1 Year Load Level 34 MW |
|---|---|---|

**Project Description:** Build the North/Arrowhead substation with a 12/20 MVA transformer and four feeders. Build 46 kV transmission tap 0.5 miles off Power Plant-Downtown 46 kV line to new sub site.

**Issue(s):** 1) 8.2 MVA on Power Plant substation transformer (5 MVA rating)

**Design Criteria Violation:**

| Element | Normal or "N-1" | Measured or Modeled Value | Design Criteria Value |
|---|---|---|---|
| Power Plant substation transformer | Normal | 8.2 MVA (modeled) 164% of rated capacity | 5 MVA |

**Benefit(s) of Project**: Reduce loading of Power Plant Transformer to 4.7 MVA. New substation provides "N-1" contingency backup/recovery for the loss of Power Plant or Downtown subs. Operational flexibility for normal and N-1 conditions.

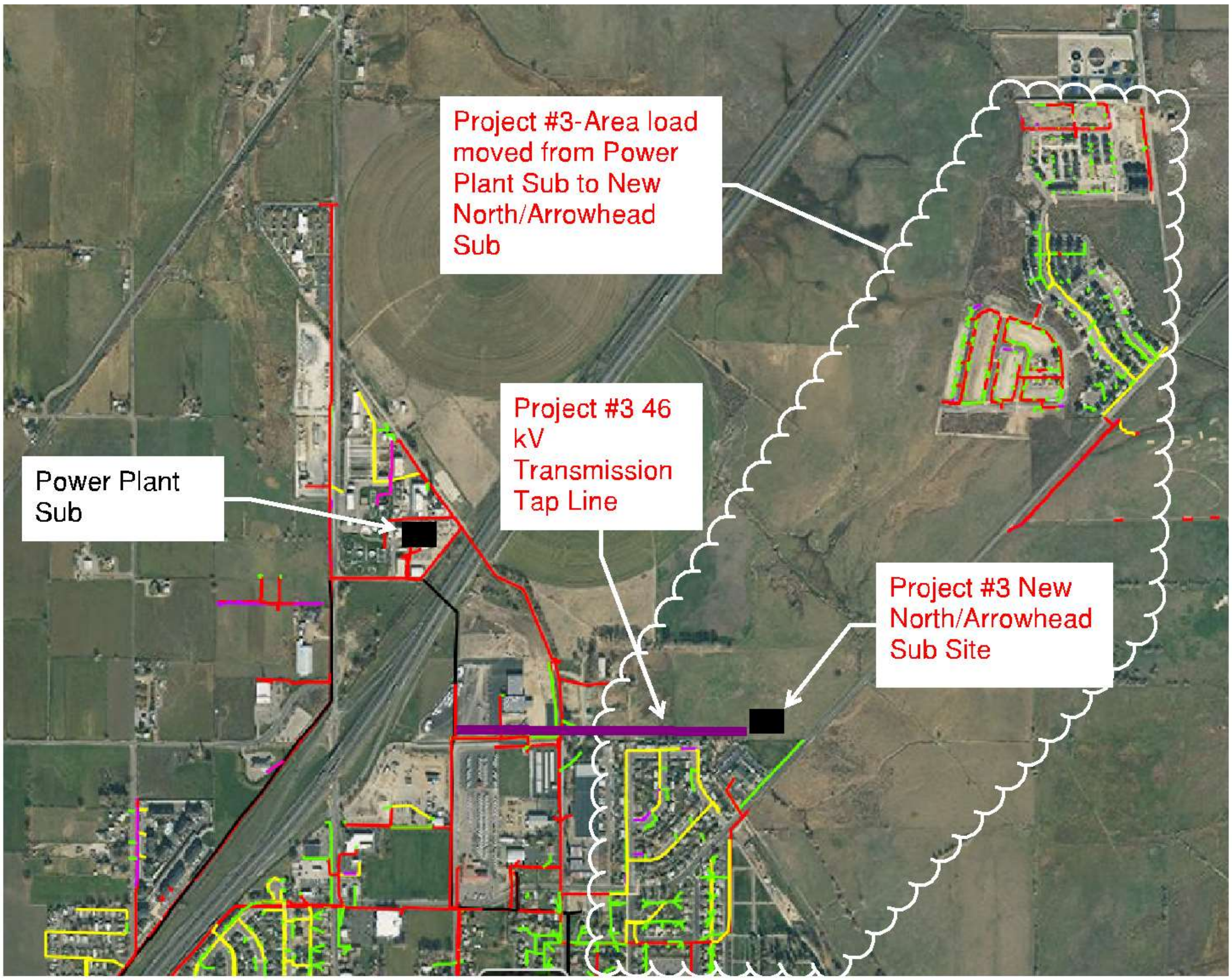
| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| Power Plant substation transformer | Normal | 4.7 MVA (modeled) 94% of rated capacity | 5 MVA |

**Opinion of Probable Cost:** $6,250,300 (does not include easements)

**Risk Assessment:** High normal loading on this 46 kV-12.47 kV transformer during peak periods leads to limitations serving the growing load and restoring outages on the system. With loading greater than the transformer rating for longer periods of time and more frequently the likelihood of transformer failure increases. Higher customer outage time and lower system resiliency are at risk.

**Alternatives Considered:** 1.) Replace the Power Plant substation transformer with a 10 MVA or larger transformer. The alternative does not mitigate the "N-1" loss of the substation transformer with another substation transformer to pick up the load of the lost transformer.

**Project #3 Map**



| Project # : 4 | Project Title: Strong Tie Feeders 510 to 730 | Priority: High–1 Year<br>Load Level 34 MW |
|---|---|---|

**Project Description:** Build tie between feeder 730 and 510 about 1700 West 800 South, with switches as needed.

**Issue(s):** 1) In 2025, 13.2 MVA on Industrial substation transformer T2 (12 MVA rating).

2) In 2025, Feeder 730 loads to 100% of its protective relay setting.

**Design Criteria Violation:**

| Element | Normal or "N-1" | Measured or Modeled Value | Design Criteria Value |
|---|---|---|---|
| Industrial substation transformer T2 | Normal | 13.2 MVA (modeled)<br>110% rated capacity | 12 MVA<br>100% rated capacity |
| Feeder 730 Protective Relay Setting | Normal | 450 amp (modeled)<br>100% of relay setting | <100% of relay setting |

**Benefit(s) of Project**: This proposed project would reduce the loading of T2 transformer to 10 MVA, and the load on feeder 730 to 310 amps. The new feeder tie provides operational flexibility for normal and N-1 conditions.

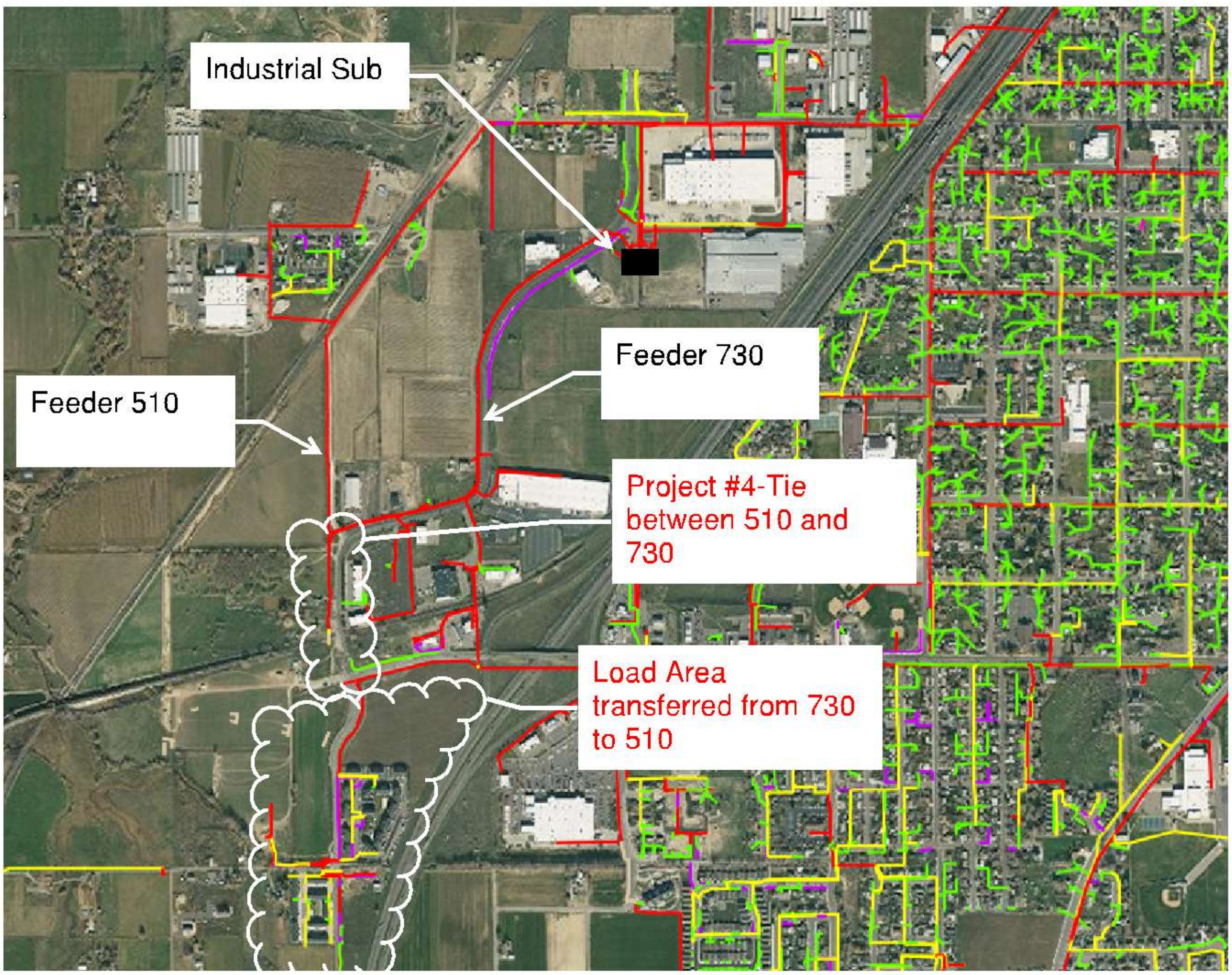
| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| Industrial substation transformer T2 | Normal | 10 MVA (modeled)<br>83% rated capacity | 12 MVA<br>100% rated capacity |
| Feeder 730 Protective Relay Setting | Normal | 310 amps (modeled)<br>69% rated capacity | <100% of relay setting |

**Opinion of Probable Cost:** $205,300 (does not include easements)

**Risk Assessment:** High normal loading on this 46 kV-12.47 kV transformer during peak periods leads to limitations serving the growing load and restoring outages on the system. With loading greater than the transformer rating for longer periods of time and more frequently the likelihood of transformer failure increases. Loading the feeder up to the protective relay setting could lead to unintended tripping of the feeder circuit breaker.

**Alternatives Considered:** Raise the protective relay setting—this does not reduce the loading on the transformer.

**Project #4 Map**



| Project # : 5 | Project Title: Rebuild/reconductor Feeder 510/610 I-15 crossing | Priority: High – 1 Year Load Level 34 MW |
|---|---|---|

**Project Description:** Reconductor/rebuild the 510/610 I-15 crossing about 200 North with about 0.4 miles (1,100 ft) with 300-amp capacity (min.) conductor.

**Issue(s):** 1) In 2023 "N-1" loss of Downtown substation, restoring feeder 310, #2/0 Al conductor loads to 248 amps (180 amp rating).

**Design Criteria Violation:**

| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| **510/610 Feeder #2/0 Al overhead** | N-1 | 248 amps<br>138% of rated capacity | 180 amps<br>100% rated capacity |

**Benefit(s) of Project**: Increased transmission system reliability and capacity of the Baxter to Compound 46 kV transmission line would be available for normal operation, for N-1 contingency outage restoration and for growth. Improved reliability with a rebuilt line and new, larger conductor.

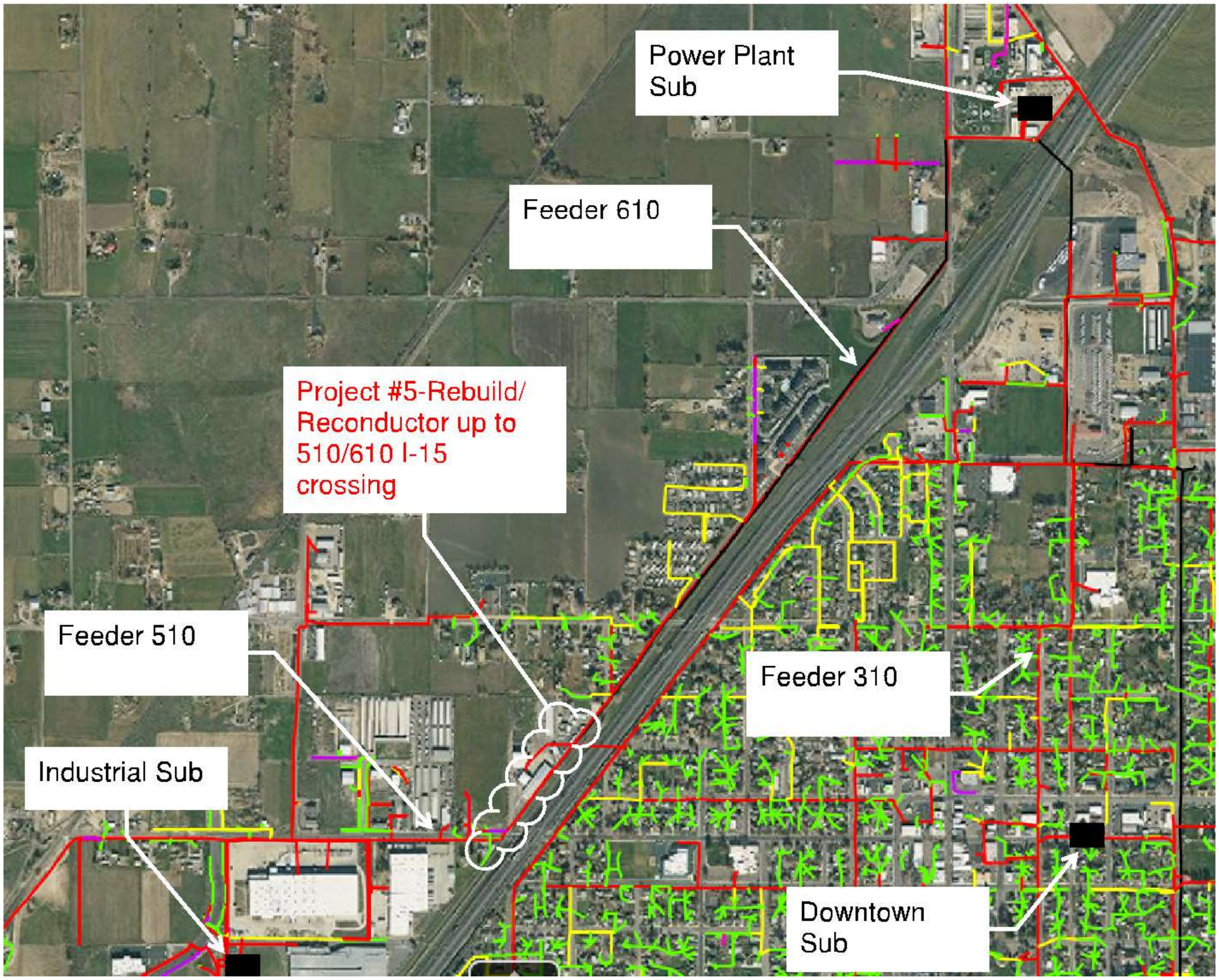
| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| **510/610 Feeder #4/0 Al ACSR overhead** | N-1 | 248 amps<br>73% of rated capacity | 340 amps<br>100% rated capacity |

**Opinion of Probable Cost:** $74,400

**Risk Assessment:** Restoration of customers on the 310 feeder would be limited by the capacity of the 510/610 conductor leading up to the I-15 crossing, upon the loss of the Downtown substation transformer.

**Alternatives Considered:** n/a

**Project #5 Map**



| Project # : 6 | Project Title: South substation feeder tie to 800 South along SR-198/500 West | Priority: High – 1 Year<br>Load Level 34 MW |
|---|---|---|

**Project Description:** Build South substation a feeder about 1.4 miles (7,350 ft) to 800 South along SR-198/500 West with 250-amp capacity (min.) conductor. Underbuilt on new transmission line to South substation.

**Issue(s):** 1) In 2023 "N-1" loss of Racetrack, restoring feeder 410, feeder 320 250 kcmil UG conductor loads to 349 amps (255 amp rating).

**Design Criteria Violation:**

| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| **320 Feeder Mainline**<br>**250 kcmil UG** | N-1 | 349 amps<br>137% | 255 amps<br>100% rated capacity |

**Benefit(s) of Project**: A strong tie between South substation and 410. Operational flexibility for normal and N-1 conditions.

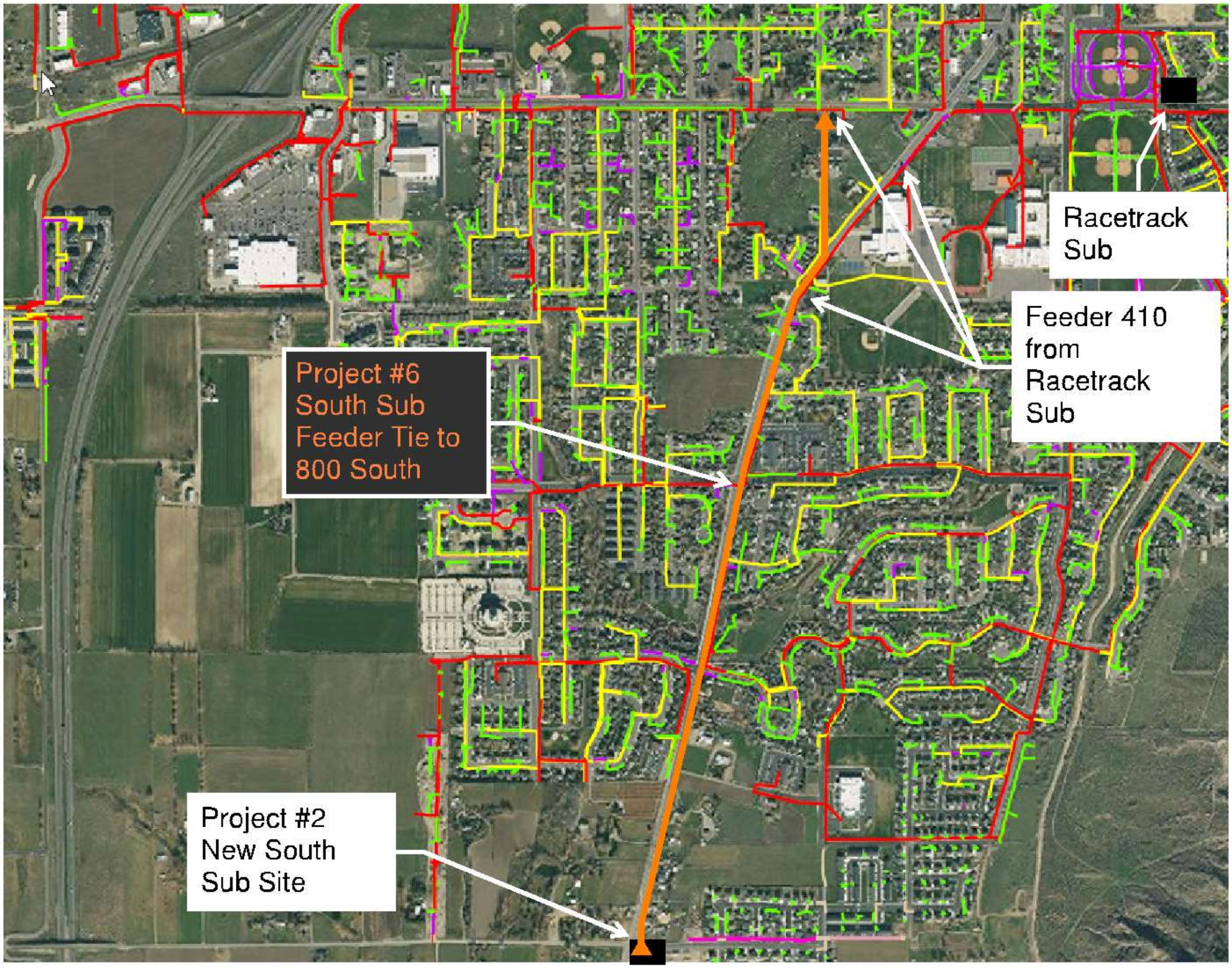
| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| **320 Feeder Mainline**<br>**250 kcmil UG** | N-1 | 186 amps<br>73% | 255 amps<br>100% rated capacity |

**Opinion of Probable Cost:** $244,100 (does not include easements)

**Risk Assessment:** Recovery from the loss of Racetrack substation transformer at peak load periods may not be possible without overloading Downtown substation feeder mainlines.

**Alternatives Considered:** n/a

**Project #6 Map**



| Project # : 7 | Project Title: Strong Tie Feeders 710 to 320 | Priority: High–1 Year<br>Load Level 34 MW |
|---|---|---|

**Project Description:** Build strong tie from 710 to 320, from Industrial substation to 300 West 300 South, about 0.83 miles (4,400 ft) with 200-amp capacity (min.) conductor. (800' underground; 4,760' overhead)

**Issue(s):** 1) In 2023 "N-1" loss of 46 kV transmission line to Downtown and Racetrack, restoring feeder 320, South substation transformer goes to 21.5 MVA (20 MVA rating).

**Design Criteria Violation:**

| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| South substation transformer | N-1 | 21.5 MVA<br>108% highest nameplate rating | 20 MVA<br>100% highest nameplate rating |

**Benefit(s) of Project**: A strong tie between Industrial substation and Downtown. Operational flexibility for normal and N-1 conditions.

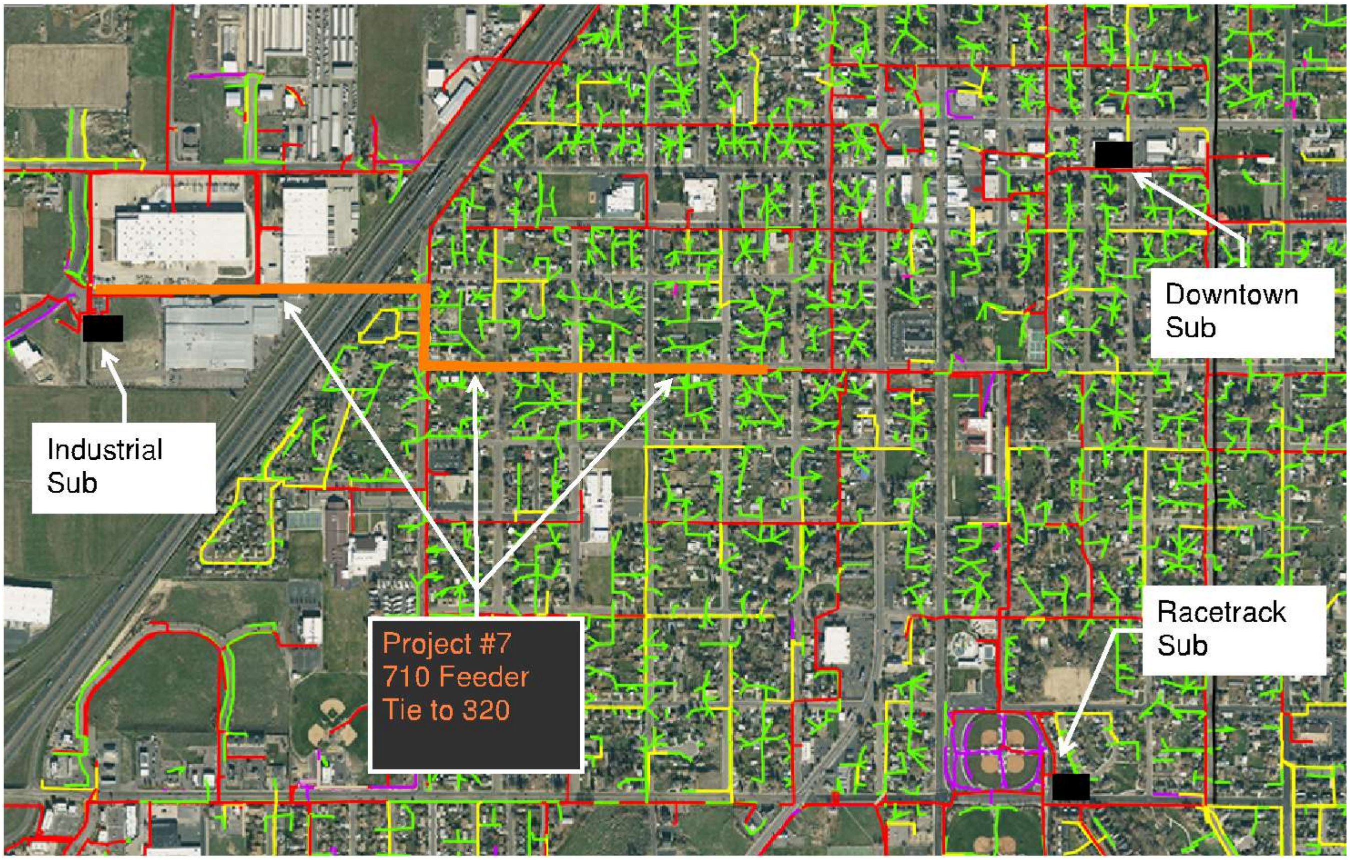
| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| South substation transformer | N-1 | 15.2 MVA<br>76% highest nameplate rating MVA | 20 MVA<br>100% highest nameplate rating |

**Opinion of Probable Cost:** $368,500 (does not include easements)

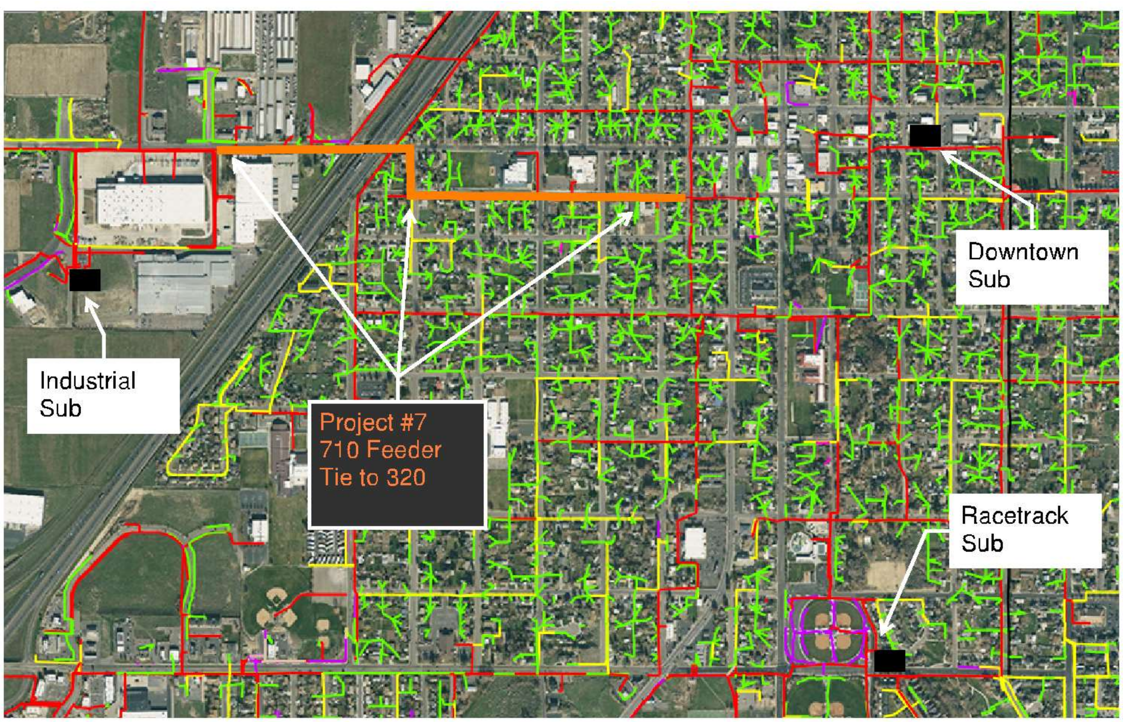
**Risk Assessment:** Recovery from the loss of the 46 kV line to Downtown and Racetrack substations at peak load periods may not be possible without overloading the South substation transformer.

**Alternatives Considered:** Build strong tie from 710 to 320, from 1000 W. Utah Ave. to 200 West 100 South. This alternative has longer underground under the Utah Ave. I-15 bridge.

## Project # 7 Map




## Project # 7 ALT. Map



| Project # : 8 | Project Title: 46 kV Transmission Loop to South substation | Priority: High– 1 Year Load Level 34 MW |
|---|---|---|

**Project Description:** Build 46 kV transmission from Industrial substation to the South substation, about 4 miles (21,000 ft) with 795 ACSR conductor.

**Issue(s):** 1) In 2023 "N-1" loss of 46 kV transmission line to Downtown and Racetrack, restoring from South substation transformer requires a loop feed to South substation. Industrial substation transformers do not have combine available capacity enough (20 MVA available capacity) for picking up 26 MVA of load.

**Design Criteria Violation:**

| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| Industrial substation transformers | N-1 | 46 MVA<br>115% highest nameplate rating on two 12/20 MVA transformers at Industrial Sub | 40 MVA<br>100% highest nameplate rating on two 12/20 MVA transformer |

**Benefit(s) of Project**: A 46 kV transmission loop, with appropriate 46 kV switches enables restoring substations for outage on sections of lines between substations. Operational flexibility for normal and N-1 conditions.

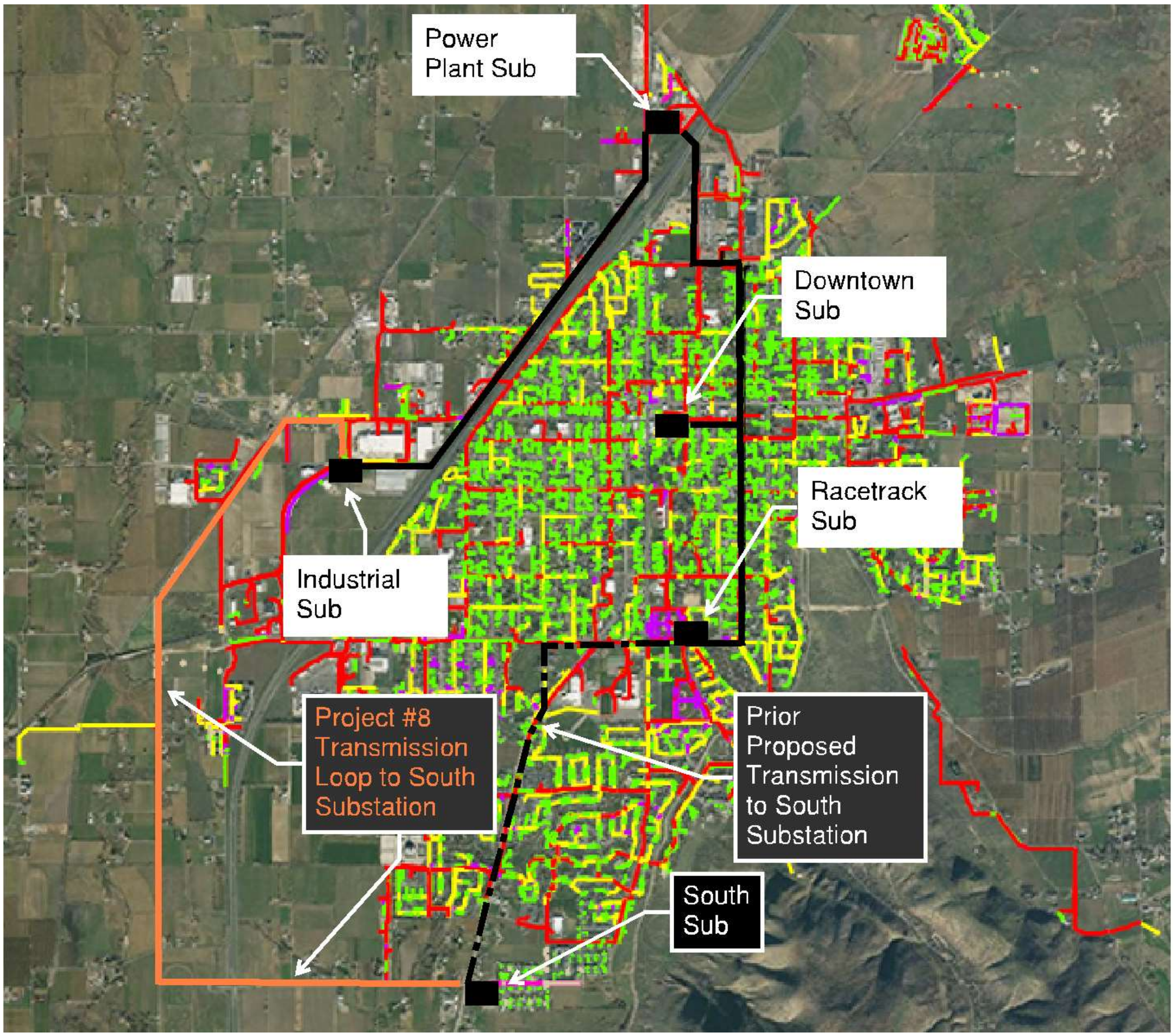
| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| Industrial substation transformers | N-1 | 30 MVA<br>75% highest nameplate rating on two 12/20 MVA transformers at Industrial Sub | 40 MVA<br>100% highest nameplate rating on two 12/20 MVA transformer |

**Opinion of Probable Cost:** $2,448,700 (does not include easements)

**Risk Assessment:** During the loss of the 46 kV transmission line to Downtown, Racetrack and South substations, the load at peak periods may be higher than the capacity of the transformers at Industrial substation.

**Alternatives Considered:** n/a

**Project # 8 Map**



| Project # : 9 | Project Title: South substation feeder 810 tie to 510/730 | Priority: High– 1 Year Load Level 34 MW |
|---|---|---|

**Project Description:** Build a South substation feeder 810 to feeder 510/730 at 1700 West 1200 South about 2.4 miles (12,900 ft) with 600-amp (250-amp min.) capacity conductor (along 12000 South 4800 West, county).

**Issue(s):** 1) In 2024 for "N-1" loss of Industrial T1, restoring feeder 510, feeder 730 mainline 500 kcmil UG conductor loads to 438 amps (385 amp rating).

**Design Criteria Violation:**

| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| **730 Feeder Mainline 500 kcmil UG** | N-1 | 438 amps<br>114% | 385 amps<br>100% rated capacity |

**Benefit(s) of Project**: A strong tie between South substation and 510. Operational flexibility for normal and N-1 conditions.

| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| **730 Feeder Mainline 500 kcmil UG** | N-1 | 244 amps<br>63% | 385 amps<br>100% rated capacity |

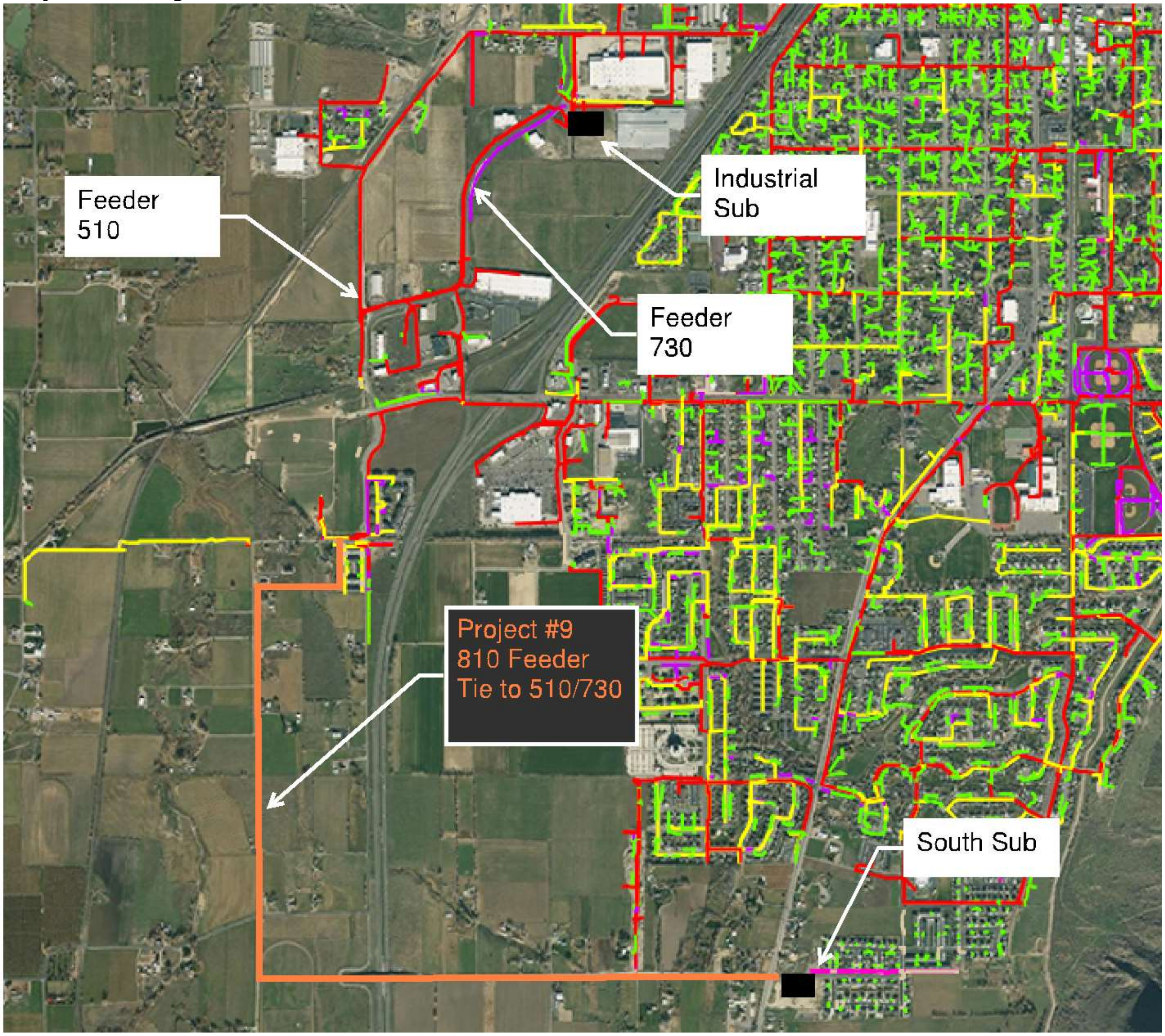
**Benefit(s) of Project**: A 600-amp tie with capacity to serve existing and new loads will be built. Operational flexibility for normal and N-1 conditions.

**Opinion of Probable Cost:** $628,000 (does not include easements; assumes all OH, includes poles—may be underbuilt on 46 kV loop if that is built at the same time or before this line, then the cost of poles can be subtracted.)

**Risk Assessment:** n/a

**Alternatives Considered:** n/a

**Project # 9 Map**



| Project # : 10 | **Project Title:** Reconductor/rebuild 330 Mainline | **Priority:** Moderate High– 3 Year Load Level 58 MW |
|---|---|---|

**Project Description:** Reconductor/rebuild feeder 330 getaway and mainline on Utah Ave, 500 East, and 100 South about 0.56 miles (2,940 ft) to 440-amp capacity (min.) conductor. 1,960 UG 980 OH

**Issue(s):** 1) 2027 "N-1" loss of Racetrack substation or Arrowhead substation, restoring feeder 420 or Arrowhead feeder, feeder 330 250 kcmil UG conductor loads to 303 amps (255 amp rating).

**Design Criteria Violation:**

| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| **330 Feeder Mainline**<br>**250 kcmil UG** | N-1 | 440 amps<br>173% | 255 amps<br>100% rated capacity |

**Benefit(s) of Project**: A greater capacity mainline on feeder 330. Operational flexibility for normal and N-1 conditions.

| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| **330 Feeder Mainline**<br>**500 MCM Cu UG** | N-1 | 440 amps<br>92% | 480 amps<br>100% rated capacity |

**Opinion of Probable Cost:** $328,800 ($369,900 in 2027 construction year)

**Risk Assessment:** Recovery from N-1 contingencies of Racetrack or Arrowhead feeders may overload the mainline of feeder 330.

**Alternatives Considered:** n/a

## Project # 10 Map

| Project # : 11 | Project Title: Reconductor/rebuild 510 Mainline | Priority: Moderate High– 3 Year Load Level 58 MW |
|---|---|---|

**Project Description:** Reconductor 510 mainline 500 MCM with 1100 MCM and 4/0 ACSR with 477 ACSR about 1.7 miles (8,850 ft) from Industrial substation to 1700 West 1200 South (tie to feeder 810).

**Issue(s):** 1) In 2027 "N-1" loss of South substation, restoring feeder 810, feeder 510 500 kcmil UG conductor and 4/0 ASCR loads to 552 amps (385 amp rating) and 382 amps (340 amp rating on 4/0 ACSR).

**Design Criteria Violation:**

| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| Feeder 510 500 kcmil UG conductor | N-1 | 552 amps<br>143% | 385 amps<br>100% rated capacity |

**Benefit(s) of Project**: A greater capacity mainline on feeder 510. Operational flexibility for normal and N-1 conditions.

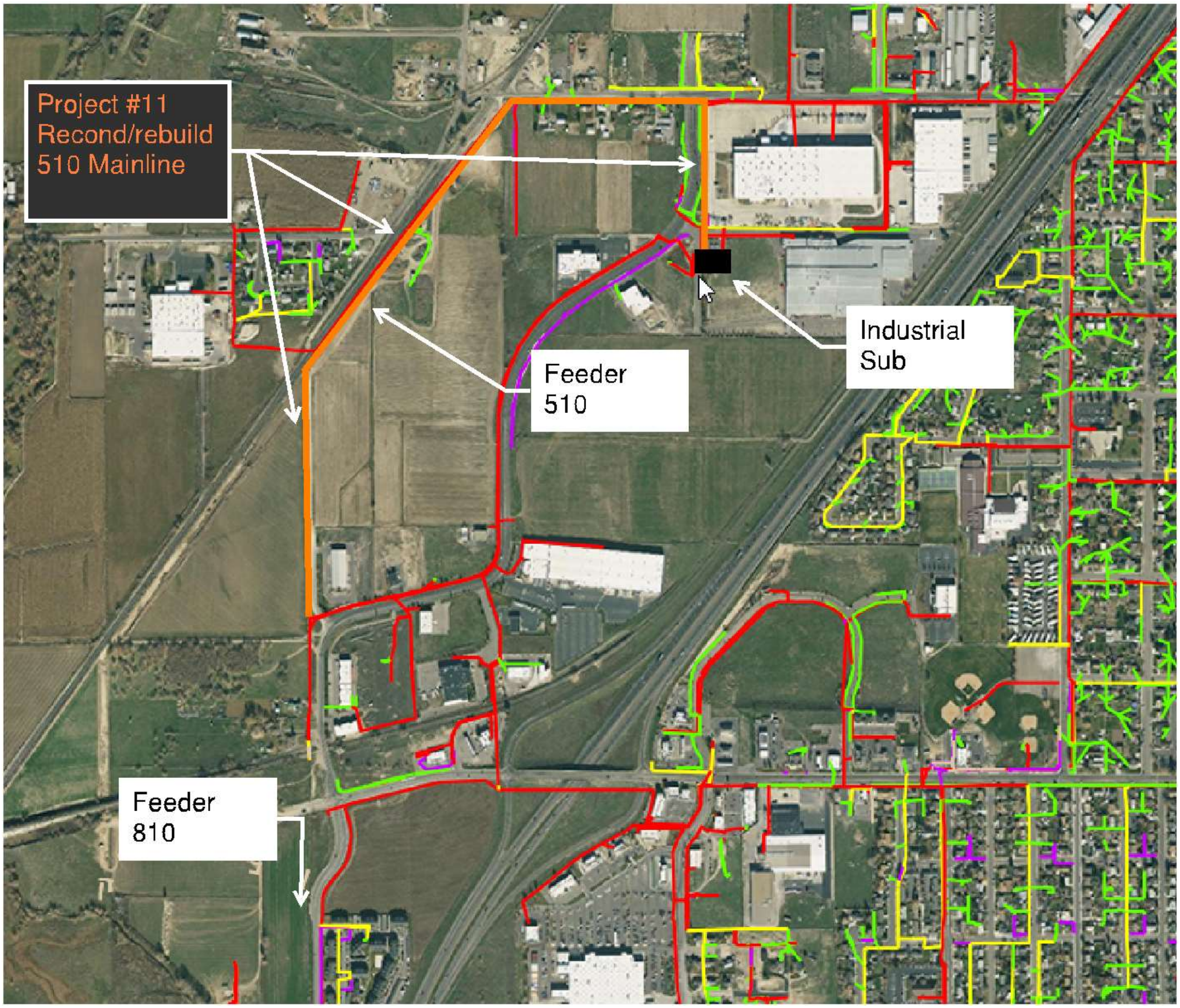
| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| Feeder 510 1100 MCM conductor | N-1 | 552 amps<br>92% | 600 amps<br>100% rated capacity |

**Opinion of Probable Cost:** $316,300 ($355,800 in 2027 construction year)

**Risk Assessment:** Recovery from N-1 contingencies of South substation feeders may overload the mainline of feeder 510.

**Alternatives Considered:** n/a

**Project # 11 Map**



| Project # : 12 | Project Title: Reconductor/rebuild 730 Mainline | Priority: Moderate High– 3 Year Load Level 58 MW |
|---|---|---|

**Project Description:** Reconductor 730 mainline underground conductor about 0.9 miles (4,800 ft) with 1100 MCM from 500 S American Way to 1700 West 1200 South (tie to feeder 810).

**Issue(s):** 1) 2027 "N-1" loss of South substation, restoring feeders 810 and 840, feeder 730 UG conductors load to 460-496 amps (330-385 amp ratings).

**Design Criteria Violation:**

| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| Feeder 730 500 kcmil UG | N-1 | 496 amps<br>129% | 385 amps<br>100% rated capacity |

**Benefit(s) of Project**: A greater capacity mainline on feeder 730. Operational flexibility for normal and N-1 conditions.

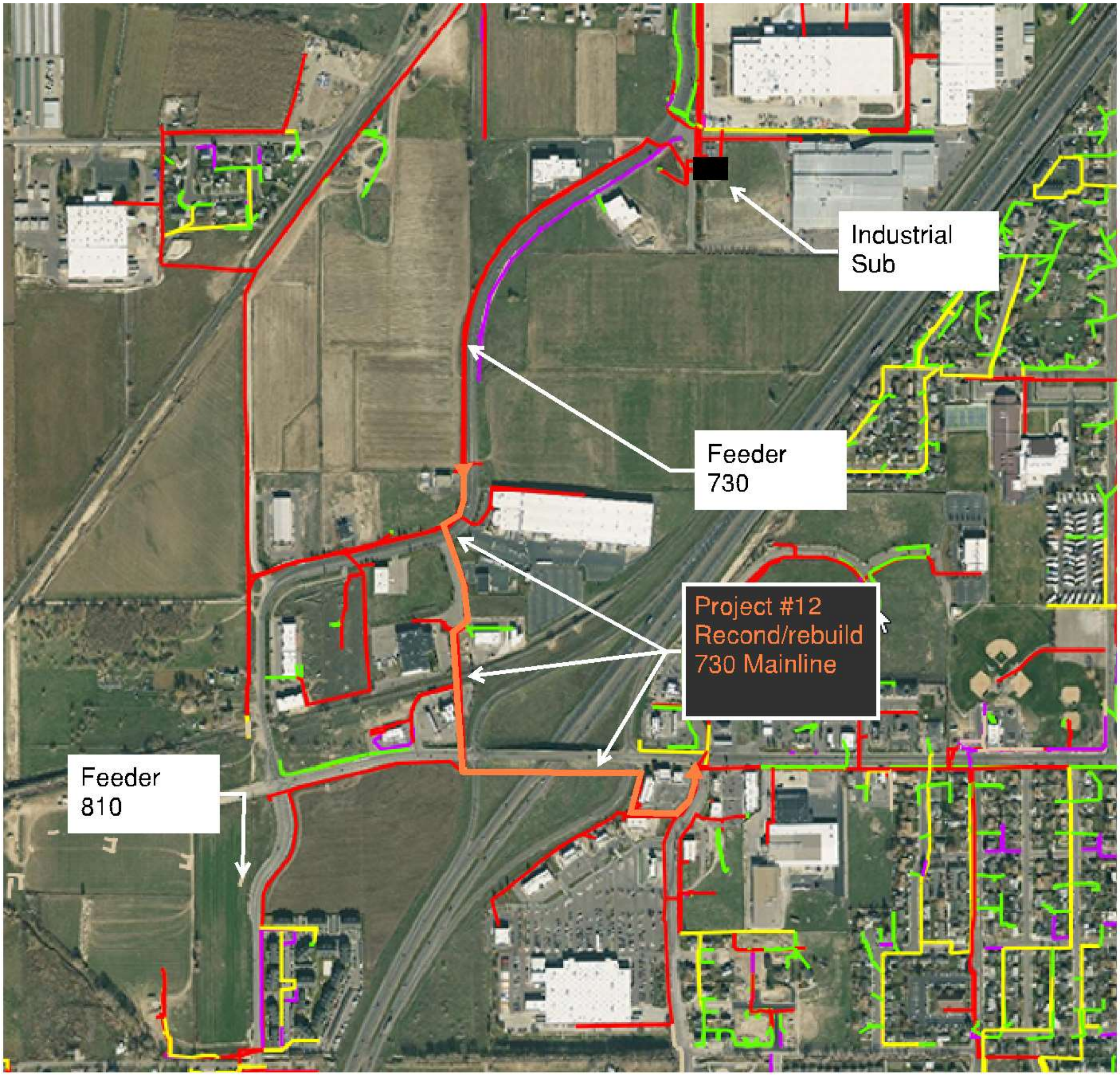
| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| Feeder 730 1100 MCM UG | N-1 | 496 amps<br>83% | 600 amps<br>100% rated capacity |

**Opinion of Probable Cost:** $544,500 ($612,500 in 2027 construction year)

**Risk Assessment:** Recovery from N-1 contingencies of South substation feeders may overload the mainline of feeder 730.

**Alternatives Considered:** n/a

**Project # 12 Map**



| Project # : 13 | Project Title: Strong Tie Feeders Arrowhead 920 to 330 | Priority: Medium–5 Year Load Level 67 MW |
|---|---|---|

**Project Description:** Build tie between 920 (from Arrowhead) to 330 with 340-amp capacity (min.) conductor along 700 East about 1 mile (5,150 ft) along 700/900 East to SR-198 (tie to 330).

**Issue(s):** 1) 2029-1. 10.12 MVA on Downtown transformer (10 MVA rating)

**Design Criteria Violation:**

| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| Downtown transformer | Normal | 10.12 MVA<br>173% | 10 MVA<br>100% rated capacity |

**Benefit(s) of Project**: A strong tie between Arrowhead and Downtown substations. Operational flexibility for normal and N-1 conditions.

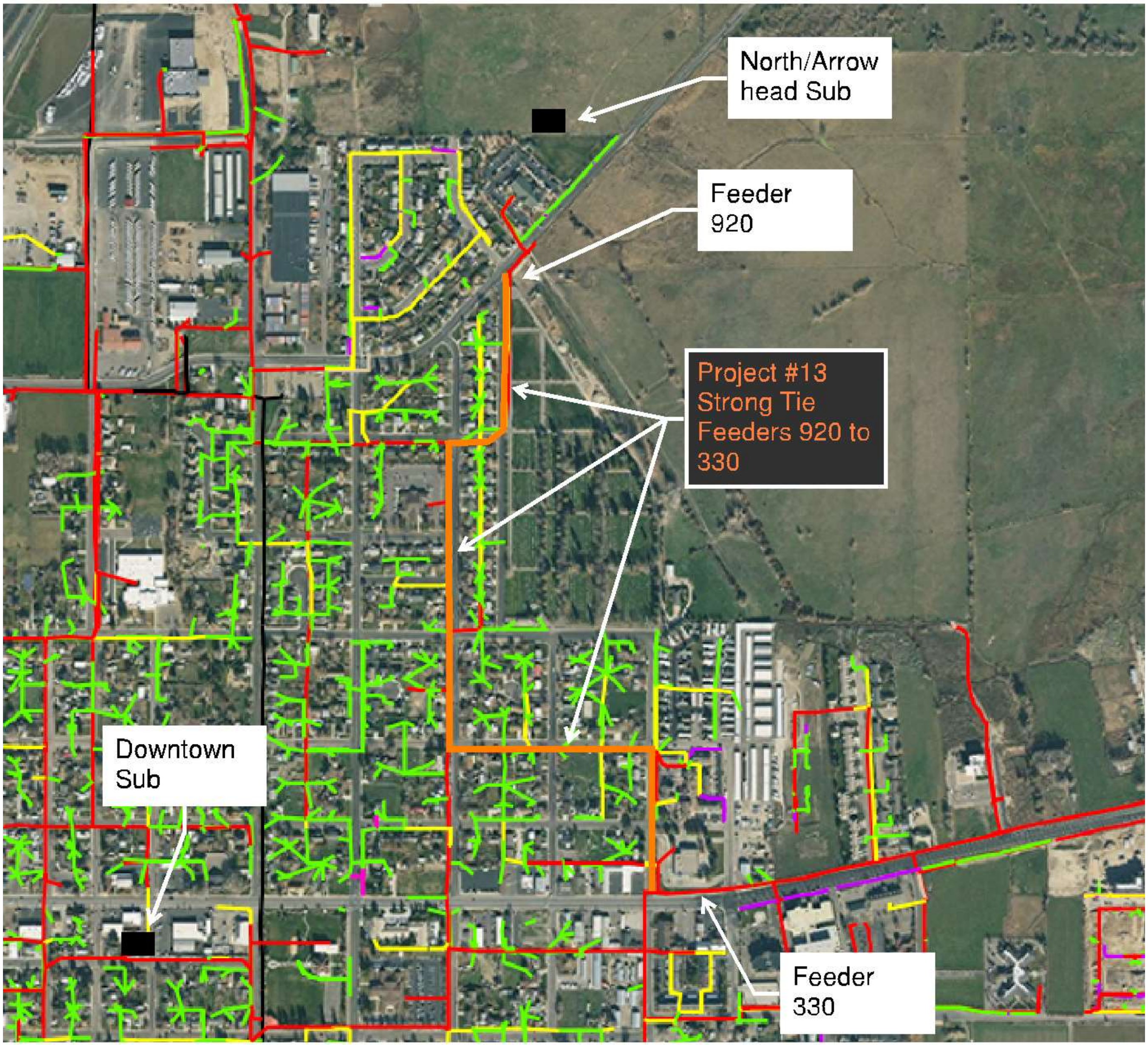
| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| Downtown transformer | Normal | 7.19 MVA<br>72% | 10 MVA<br>100% rated capacity |

**Opinion of Probable Cost:** $408,100 ($496,600 in 2029 construction year)

**Risk Assessment:** Recovery from N-1 contingencies of Racetrack or Arrowhead feeders may overload the mainline of feeder 330.

**Alternatives Considered:** n/a

**Project # 13 Map**



| Project # : 14 | Project Title: Build Southwest area Substation and Feeders | Priority: Medium– 5 Year Load Level 67 MW |
|---|---|---|

**Project Description:** Build Southwest area substation with 12/20 MVA transformer and four feeders. Build 46 kV transmission tap 0.5 miles off Industrial-South sub 46 kV line to new sub site.

**Issue(s):** 1) 2029 "N-1" loss of South substation, loads Industrial substation transformer T2 to 24.8 MVA (20 MVA rating).

2) 2033 "N-0" system substation loading goes to 81.1 MVA (total "N-0" capacity 73 MVA).

**Design Criteria Violation:**

| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| Industrial substation transformer T2 | N-1 | 24.8 MVA<br>124% | 20 MVA<br>100% highest nameplate rated capacity |
| System substation loading | Normal | 81.1 MVA<br>111% | 73 MVA<br>100% rated capacity |

**Benefit(s) of Project**: New substation capacity becomes available in the southwest area for new growth there. Operational flexibility for normal and N-1 conditions.

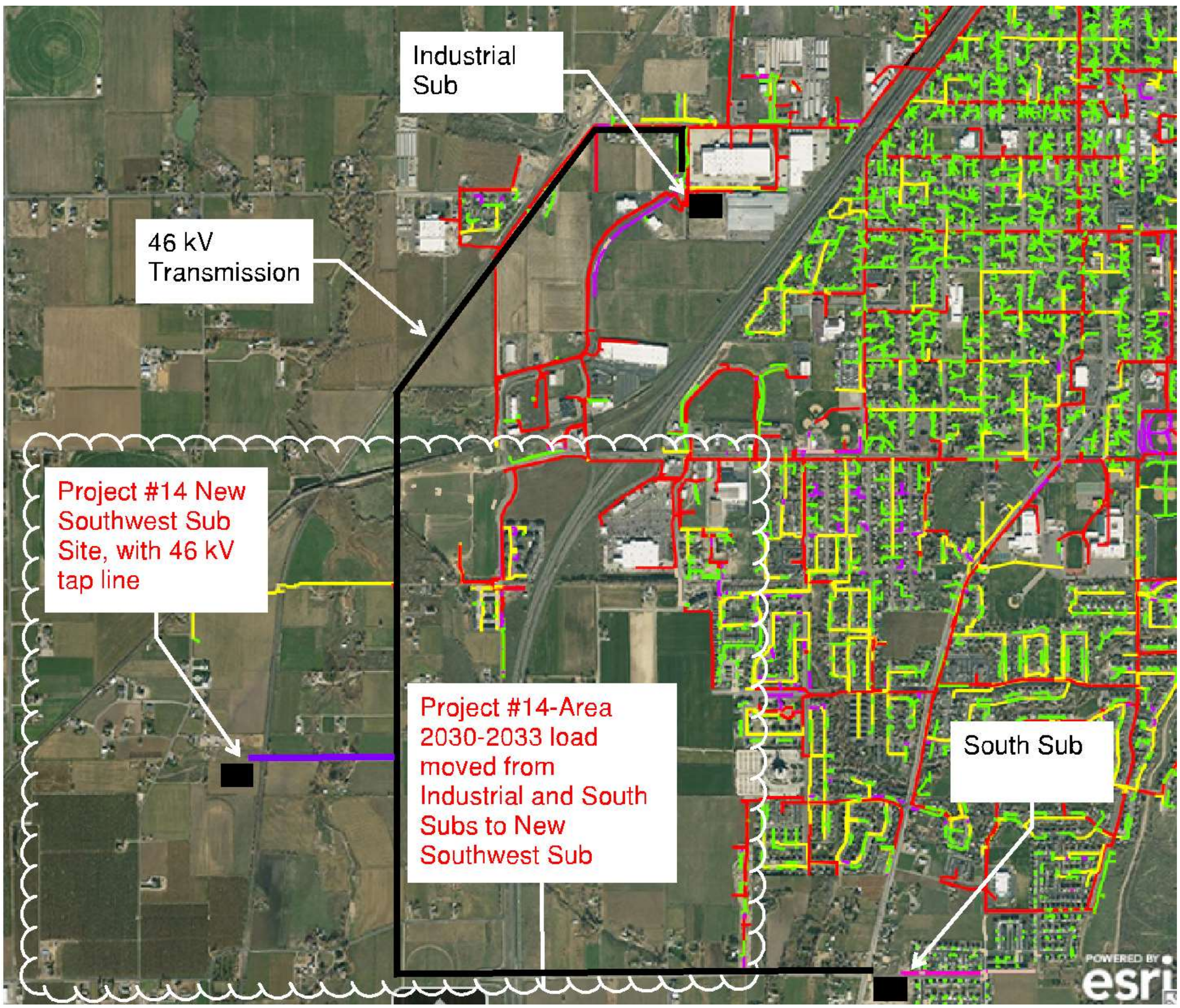
| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| Industrial substation transformer T2 | N-1 | 7.67 MVA<br>38% | 20 MVA<br>100% highest nameplate rated capacity |
| System substation loading | Normal | 81.1 MVA<br>95% | 85 MVA<br>100% rated capacity |

**Opinion of Probable Cost:** $6,250,300 ($7,604,500 in 2029 construction year)

**Risk Assessment:** Normal loading in 2030-2033 and Recovery from N-1 contingencies of the South substation may overload the system and Industrial substation transformers.

**Alternatives Considered:** n/a

**Project # 14 Map**



| Project # : 15 | Project Title: Build new North area Substation and Feeders | Priority: Medium– 5 Year Load Level 67 MW |
|---|---|---|

**Project Description:** Build North area substation with 12/20 MVA transformer and four feeders. Build 46 kV transmission tap 0.5 miles off Power Plant-Downtown 46 kV line to new sub site.

**Issue(s):** 1) 2029 "N-1" loss of Arrowhead substation, loads Downtown substation transformer to 16.5 MVA (12 MVA rating).

**Design Criteria Violation:**

| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| Downtown transformer | N-1 | 16.5 MVA<br>138% | 12 MVA<br>100% highest nameplate rated capacity |

**Benefit(s) of Project**: New substation capacity becomes available in the north area for new growth there. Operational flexibility for normal and N-1 conditions

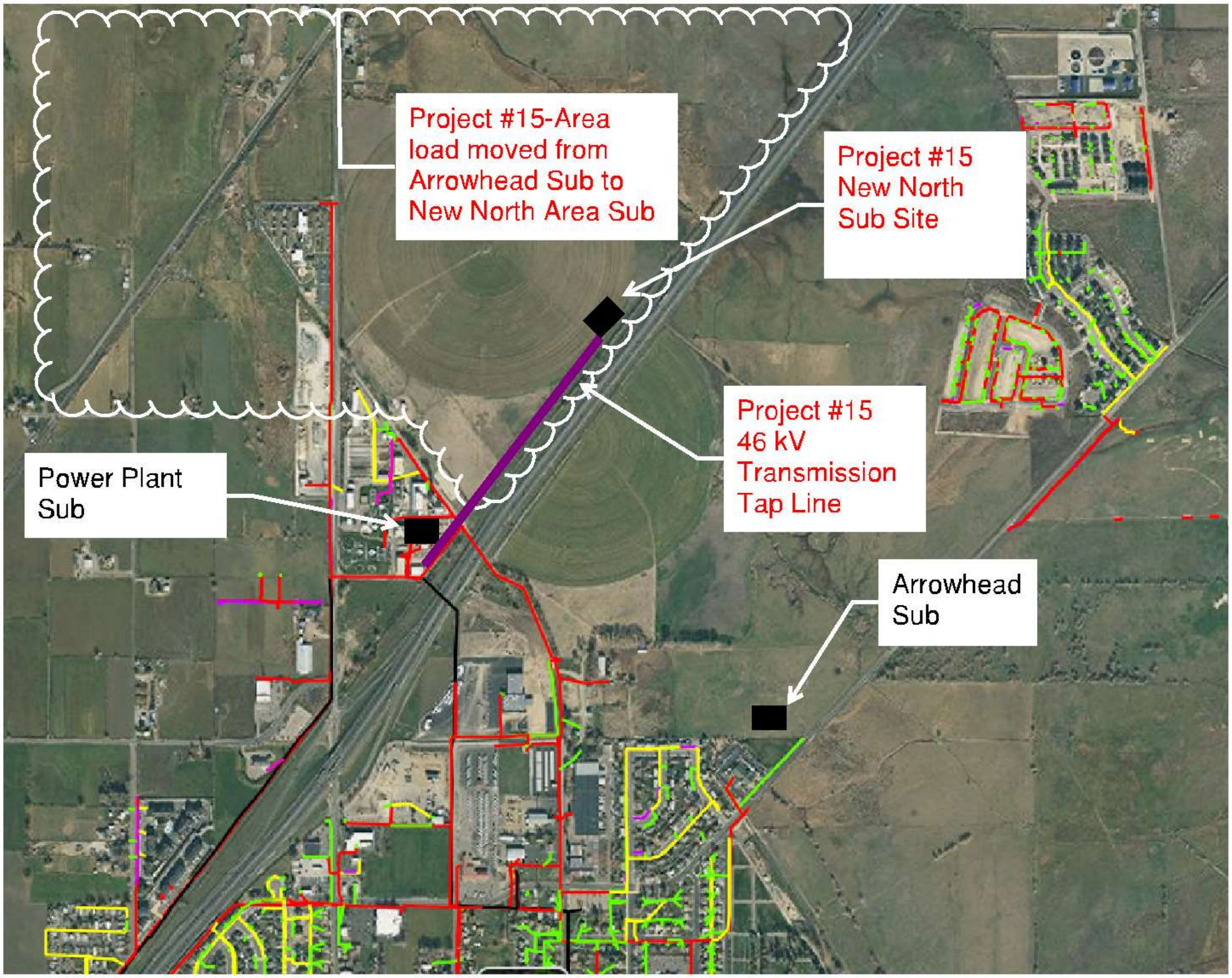
| Element | Normal or "N-1" | Modeled Value | Design Criteria Value |
|---|---|---|---|
| Downtown transformer | N-1 | 10.2 MVA<br>85% | 12 MVA<br>100% highest nameplate rated capacity |

**Opinion of Probable Cost:** $6,250,300 ($7,604,500 in 2029 construction year)

**Risk Assessment:** Recovery from N-1 contingencies of Arrowhead substation may overload the Downtown transformer.

**Alternatives Considered:** n/a

**Project # 15 Map**



# 8. APPENDIX B: LOAD FORECAST BY FEEDER

**Payson Power**
**Load Forecast**

| 2023 | to | 2033 |
|---|---|---|

| Substation/Circuit | | New Load or Transfer | Growth Rate | Transformer/Circuit Rating (MVA/Amps) | | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | Utilization |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Industrial** | | | | 24 | MVA | | | | | | | | | | | | |
| **Industrial-T1** | | | | 12 | MVA | 4.20 | 4.29 | 9.39 | 11.13 | 11.38 | 11.44 | 11.49 | 11.55 | 11.60 | 11.66 | 11.72 | 98% |
| | **510** | base yr. peak | 1.24% | 380 | Amps | 61 | 62 | 63 | 63 | 64 | 65 | 66 | 66 | 67 | 68 | 69 | |
| | | Transfer from 610 | | | | | | 142 | | | | | | | | | |
| | | Transfer from 730 | | | | | | 83 | | | | | | | | | |
| | | Hiatt Crk | | | | | | 9 | | | | | | | | | |
| | | Hiatt Crk | | | | | | | 9 | | | | | | | | |
| | | M-Tech Red Bridge | | | | | | | 69 | | | | | | | | |
| | | Hiatt Crk | | | | | | | | 9 | | | | | | | |
| | | Adjusted load | | | Amps | 61 | 62 | 297 | 375 | 385 | 386 | 387 | 387 | 388 | 389 | 390 | 103% |
| | **520** | base yr. peak | 1.24% | 380 | Amps | 135 | 137 | 138 | 140 | 142 | 144 | 145 | 147 | 149 | 151 | 153 | |
| | | Adjusted load | | | Amps | 135 | 137 | 138 | 140 | 142 | 144 | 145 | 147 | 149 | 151 | 153 | 40% |
| **Industrial-T2** | | | | 12 | MVA | 11.70 | 11.85 | 9.86 | 10.01 | 10.55 | 10.89 | 11.05 | 11.20 | 11.36 | 11.52 | 11.68 | 97% |
| | **710** | base yr. peak | 1.24% | 450 | Amps | 139 | 141 | 142 | 144 | 146 | 148 | 150 | 151 | 153 | 155 | 157 | |
| | | Adjusted load | | | Amps | 139 | 141 | 142 | 144 | 146 | 148 | 150 | 151 | 153 | 155 | 157 | 35% |
| | **720** | base yr. peak | 1.24% | 450 | Amps | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | | Business Park | | | | | | | | 81 | | | | | | | |
| | | Adjusted load | | | Amps | 0 | 0 | 0 | 0 | 81 | 81 | 81 | 81 | 81 | 81 | 81 | 18% |
| | **730** | base yr. peak | 1.24% | 450 | Amps | 403 | 408 | 413 | 418 | 423 | 429 | 434 | 439 | 445 | 450 | 456 | |
| | | Transfer to 810 | | | | | | -16 | | | | | | | | | |
| | | Transfer to 510 | | | | | | -83 | | | | | | | | | |
| | | Transfer to 840 | | | | | | | | -63 | | | | | | | |
| | | Hiatt Crk | | | | | | | | | 9 | | | | | | |
| | | Adjusted load | | | Amps | 403 | 408 | 314 | 319 | 261 | 276 | 281 | 286 | 292 | 297 | 303 | 67% |
| Industrial Sub Total | | | | | MVA | 15.90 | 16.14 | 19.25 | 21.14 | 21.93 | 22.33 | 22.54 | 22.75 | 22.97 | 23.18 | 23.40 | |
| | | | | | | | | | | | | | | | | | |
| **Power Plant** | | | | 5 | MVA | | | | | | | | | | | | |
| **Power Plant-T1** | | | | 5 | MVA | 7.00 | 7.11 | 4.65 | 4.73 | 4.83 | 4.92 | 5.01 | 5.10 | 5.20 | 5.29 | 5.39 | 108% |
| | **610** | base yr. peak | 1.24% | 270 | Amps | 172 | 174 | 176 | 178 | 181 | 183 | 185 | 187 | 190 | 192 | 195 | |
| | | Transfer to 510 | | | | | | -142 | | | | | | | | | |
| | | Industrial | | | | | | 69 | | | | | | | | | |
| | | VA | | | | | | 20 | | | | | | | | | |
| | | Geneva Rock | | | | | | 21 | | | | | | | | | |
| | | Adjusted load | | | Amps | 172 | 174 | 144 | 146 | 149 | 151 | 153 | 155 | 158 | 160 | 163 | 60% |
| | **620** | base yr. peak | 1.24% | 270 | Amps | 153 | 155 | 157 | 159 | 161 | 163 | 165 | 167 | 169 | 171 | 173 | |
| | | Transfer to 910 | | | | | | -86 | | | | | | | | | |
| | | Adjusted load | | | Amps | 153 | 155 | 71 | 73 | 75 | 77 | 79 | 81 | 83 | 85 | 87 | 32% |
| Power Plant Sub Total | | | | | MVA | 7.00 | 7.11 | 4.65 | 4.73 | 4.83 | 4.92 | 5.01 | 5.10 | 5.20 | 5.29 | 5.39 | |

**Payson Power**
**Load Forecast**

| 2023 | to | 2033 |
|---|---|---|

| Substation/Circuit | | New Load or Transfer | Growth Rate | Transformer/Circuit Rating (MVA/Amps) | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | Utilization |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Race Track** | | | | 10 MVA | | | | | | | | | | | | |
| **Race Track T1** | | | | 10 MVA | 12.40 | 12.60 | 11.48 | 11.63 | 10.87 | 11.03 | 11.19 | 11.36 | 11.52 | 11.69 | 11.87 | 119% |
| | **410** | base yr. peak | 1.24% | 380 Amps | 218 | 221 | 223 | 226 | 229 | 232 | 235 | 238 | 241 | 244 | 247 | |
| | | Adjusted load | | Amps | 218 | 221 | 223 | 226 | 229 | 232 | 235 | 238 | 241 | 244 | 247 | 65% |
| | **420** | base yr. peak | 1.24% | 380 Amps | 135 | 137 | 138 | 140 | 142 | 144 | 145 | 147 | 149 | 151 | 153 | |
| | | Transfer from 330 | | | | | 46 | | | | | | | | | |
| | | Adjusted load | | Amps | 135 | 137 | 184 | 186 | 188 | 190 | 191 | 193 | 195 | 197 | 199 | 52% |
| | **430** | base yr. peak | 1.24% | 380 Amps | 223 | 226 | 229 | 231 | 234 | 237 | 240 | 243 | 246 | 249 | 252 | |
| | | Transfer to 830 | | | | | -57 | | | | | | | | | |
| | | Transfer to 820 | | | | | -48 | | | | | | | | | |
| | | Transfer to 840 | | | | | | | -43 | | | | | | | |
| | | Adjusted load | | Amps | 223 | 226 | 124 | 126 | 86 | 89 | 92 | 95 | 98 | 101 | 104 | 27% |
| Race Track Sub Total | | | | MVA | 12.40 | 12.60 | 11.48 | 11.63 | 10.87 | 11.03 | 11.19 | 11.36 | 11.52 | 11.69 | 11.87 | |
| **Downtown** | | | | 10 MVA | | | | | | | | | | | | |
| **Downtown-T1** | | | | 10 MVA | 9.30 | 9.45 | 8.57 | 8.69 | 8.81 | 8.93 | 9.05 | 9.18 | 9.30 | 9.43 | 9.56 | 96% |
| | **310** | base yr. peak | 1.24% | 380 Amps | 112 | 113 | 115 | 116 | 118 | 119 | 121 | 122 | 124 | 125 | 127 | |
| | | Adjusted load | | Amps | 112 | 113 | 115 | 116 | 118 | 119 | 121 | 122 | 124 | 125 | 127 | 33% |
| | **320** | base yr. peak | 1.24% | 380 Amps | 125 | 127 | 128 | 130 | 131 | 133 | 135 | 136 | 138 | 140 | 141 | |
| | | Adjusted load | | Amps | 125 | 127 | 128 | 130 | 131 | 133 | 135 | 136 | 138 | 140 | 141 | 37% |
| | **330** | base yr. peak | 1.24% | 380 Amps | 195 | 197 | 200 | 202 | 205 | 207 | 210 | 213 | 215 | 218 | 221 | |
| | | Transfer to 420 | | | | | -46 | | | | | | | | | |
| | | Adjusted load | | Amps | 195 | 197 | 154 | 156 | 159 | 161 | 164 | 167 | 169 | 172 | 175 | 46% |
| Downtown Sub Total | | | | MVA | 9.30 | 9.45 | 8.57 | 8.69 | 8.81 | 8.93 | 9.05 | 9.18 | 9.30 | 9.43 | 9.56 | |
| **New North Arrowhead** | | | | 12 MVA | | | | | | | | | | | | |
| **Arrowhead North-T1** | | | | 12 MVA | 0.00 | 0.00 | 3.30 | 4.51 | 6.29 | 7.82 | 7.97 | 7.97 | 10.89 | 10.89 | 10.89 | 91% |
| | **910** | base yr. peak | 1.24% | 600 Amps | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | | Transfer from 620 | | | | | 86 | | | | | | | | | |
| | | Villages AH Park | | | | | 8 | | | | | | | | | |
| | | Arrowhead Ranch | | | | | 59 | | | | | | | | | |
| | | Villages AH Park | | | | | | 19 | | | | | | | | |
| | | Arrowhead Ranch | | | | | | 37 | | | | | | | | |
| | | Villages AH Park | | | | | | | 26 | | | | | | | |
| | | Arrowhead Ranch | | | | | | | 56 | | | | | | | |
| | | Villages AH Park | | | | | | | | 19 | | | | | | |
| | | Arrowhead Ranch | | | | | | | | 52 | | | | | | |
| | | Arrowhead Ranch | | | | | | | | | 7 | | | | | |
| | | Adjusted load | | Amps | 0 | 0 | 153 | 209 | 291 | 362 | 369 | 369 | 369 | 369 | 369 | 62% |
| | **920** | base yr. peak | 1.24% | 600 Amps | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | | Adjusted load | | Amps | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0% |
| | **930** | base yr. peak | 1.24% | 600 Amps | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | | UVU | | | | | | | | | | | 135 | | | |
| | | Adjusted load | | Amps | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 135 | 135 | 135 | 23% |
| Arrowhead North Sub Total | | | | MVA | 0.00 | 0.00 | 3.30 | 4.51 | 6.29 | 7.82 | 7.97 | 7.97 | 10.89 | 10.89 | 10.89 | |

**Payson Power**
**Load Forecast**

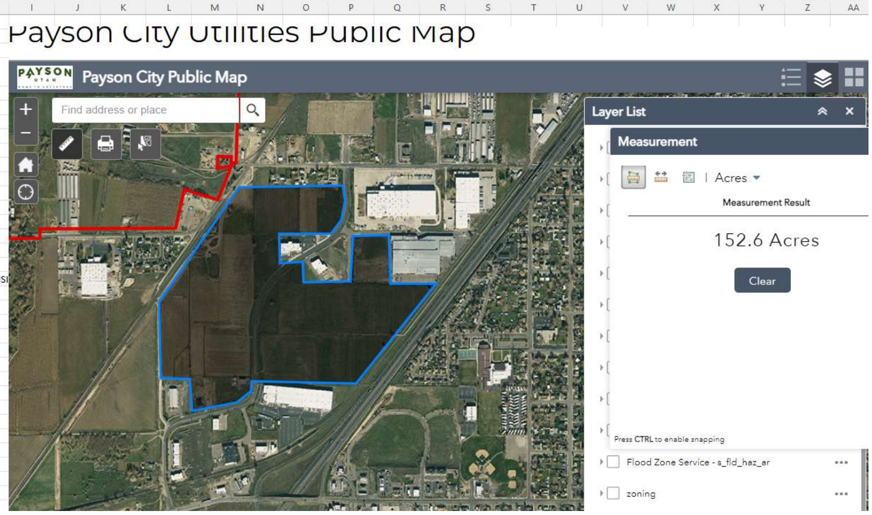
| 2023 | to | 2033 |
|---|---|---|

| Substation/Circuit | | New Load or Transfer | Growth Rate | Transformer/Circuit Rating (MVA/Amps) | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | Utilization |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **New South** | | | | 12 MVA | | | | | | | | | | | | |
| **New South-T1** | | | | 12 MVA | 0.00 | 0.00 | 3.74 | 4.62 | 8.66 | 10.43 | 10.43 | 10.43 | 10.43 | 10.43 | 10.43 | 87% |
| | **810** | base yr. peak | 1.24% | 600 Amps | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | | Transfer from 730 | | | | | 16 | | | | | | | | | |
| | | Red Bridge | | | | | 48 | | | | | | | | | |
| | | Red Bridge | | | | | | 37 | | | | | | | | |
| | | Red Bridge | | | | | | | 78 | | | | | | | |
| | | Red Bridge | | | | | | | | 82 | | | | | | |
| | | Adjusted load | | Amps | 0 | 0 | 64 | 101 | 179 | 261 | 261 | 261 | 261 | 261 | 261 | 44% |
| | **820** | base yr. peak | 1.24% | 600 Amps | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | | Transfer from 430 | | | | | 48 | | | | | | | | | |
| | | The Springs at Spring Lake | | | | | 4 | | | | | | | | | |
| | | The Springs at Spring Lake | | | | | | 4 | | | | | | | | |
| | | The Springs at Spring Lake | | | | | | | 3 | | | | | | | |
| | | Adjusted load | | Amps | 0 | 0 | 52 | 56 | 59 | 59 | 59 | 59 | 59 | 59 | 59 | 10% |
| | **830** | base yr. peak | 1.24% | 600 Amps | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | | Transfer from 430 | | | | | 57 | | | | | | | | | |
| | | Adjusted load | | Amps | 0 | 0 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 10% |
| | **840** | base yr. peak | 1.24% | 600 Amps | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | | Transfer from 730 | | | | | | | 63 | | | | | | | |
| | | Transfer from 430 | | | | | | | 43 | | | | | | | |
| | | Adjusted load | | Amps | 0 | 0 | 0 | 0 | 106 | 106 | 106 | 106 | 106 | 106 | 106 | 18% |
| New South Sub Total | | | | MVA | 0.00 | 0.00 | 3.74 | 4.62 | 8.66 | 10.43 | 10.43 | 10.43 | 10.43 | 10.43 | 10.43 | |
| | | | | | | | | | | | | | | | | |
| **New West** | | | | 24 MVA | | | | | | | | | | | | |
| **New West-T1** | | | | 12 MVA | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 4.41 | 6.18 | 7.32 | 7.32 | 9.53 | 79% |
| | **1010** | base yr. peak | 1.24% | 600 Amps | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | | Business Park | | | | | | | | | 122 | | | | | |
| | | Red Bridge | | | | | | | | | | 82 | | | | |
| | | Adjusted load | | Amps | 0 | 0 | 0 | 0 | 0 | 0 | 122 | 204 | 204 | 204 | 204 | 34% |
| | **1020** | base yr. peak | 1.24% | 600 Amps | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | | Red Bridge | | | | | | | | | 82 | | | | | |
| | | Red Bridge | | | | | | | | | | | 53 | | | |
| | | Business Park | | | | | | | | | | | | | 102 | |
| | | Adjusted load | | Amps | 0 | 0 | 0 | 0 | 0 | 0 | 82 | 82 | 135 | 135 | 237 | 40% |
| New West Sub Total | | | | MVA | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 4.41 | 6.18 | 7.32 | 7.32 | 9.53 | |

# 9. APPENDIX C: LOAD ESTIMATE BASIS FOR MAJOR DEVELOPMENTS

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential Demand Growth | | 8 | kVA | per residential unit assumed | | | | | | | | | |
| | | | | | | | | | | | | | |
| **Development Area** | | Year | | | | | | | | | | | |
| | | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | | |
| 570 Lots & Townhome | Units/yr | 0 | 160 | 100 | 150 | 140 | 20 | 0 | 0 | 0 | 0 | | |
| Arrowhead Ranch | Accum Units | 0 | 160 | 260 | 410 | 550 | 570 | 570 | 570 | 570 | 570 | 570 | **Total Units** |
| 1260 N 1400 E | Load Inc/Yr kVA | 0 | 1280 | 800 | 1200 | 1120 | 160 | 0 | 0 | 0 | 0 | 4560 | **Total kVA estimated** |
| | | | | | | | | | | | | | |
| 192 Lots & Townhome | Units/yr | 0 | 22 | 50 | 70 | 50 | 0 | 0 | 0 | 0 | 0 | | |
| Villages at AH Park | Accum Units | 0 | 22 | 72 | 142 | 192 | 192 | 192 | 192 | 192 | 192 | 192 | **Total Units** |
| 1420 N 1190 E | Load Inc/Yr kVA | 0 | 176 | 400 | 560 | 400 | 0 | 0 | 0 | 0 | 0 | 1536 | **Total kVA estimated** |
| | | | | | | | | | | | | | |
| 1241 Units | Units/yr | 0 | 129 | 100 | 210 | 220 | 220 | 220 | 142 | 0 | 0 | | |
| Red Bridge | Accum Units | 0 | 129 | 229 | 439 | 659 | 879 | 1099 | 1241 | 1241 | 1241 | 1241 | **Total Units** |
| 1950 W 1130 S | Load Inc/Yr kVA | 0 | 1041 | 807 | 1695 | 1775 | 1775 | 1775 | 1146 | 0 | 0 | 10015 | **Total kVA estimated** |
| | | | | | | | | | | | | | |
| 100 Units | Units/yr | 0 | 25 | 25 | 25 | 25 | 0 | 0 | 0 | 0 | 0 | | |
| Hiatt Crk | Accum Units | 0 | 25 | 50 | 75 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | **Total Units** |
| 1950 W 1130 S | Load Inc/Yr kVA | 0 | 202 | 202 | 202 | 202 | 0 | 0 | 0 | 0 | 0 | 807 | **Total kVA estimated** |
| | | | | | | | | | | | | | |
| 32 Lots | Units/yr | 0 | 12 | 12 | 8 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| The Springs at SL | Accum Units | 0 | 12 | 24 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | **Total Units** |
| 2000 S 600 W | Load Inc/Yr kVA | 0 | 97 | 97 | 65 | 0 | 0 | 0 | 0 | 0 | 0 | 258 | **Total kVA estimated** |
| | | | | | | | | | | | | | |
| All Developments | Units/yr | 0 | 348 | 287 | 463 | 435 | 240 | 220 | 142 | 0 | 0 | | |
| Yearly | Accum Units | 0 | 348 | 635 | 1098 | 1533 | 1773 | 1993 | 2135 | 2135 | 2135 | **2135** | **Grand Total Units** |
| Impact/Increase | Load Inc/Yr kVA | 0 | 2796 | 2306 | 3721 | 3497 | 1935 | 1775 | 1146 | 0 | 0 | **17176** | **Gand Total kVA estimated** |

| A | B | C | D | E |
|---|---|---|---|---|
| **Industrial Business Park** | | | | |
| | | | | |
| Spatial Load Estimates | DATA | | | |
| Existing | 2023 Load kVA | Acres | kVA/Acre | |
| RM ATV | 511 | 11 | 46 | |
| Liberty Safe | 1574 | 23 | 68 | |
| PPC Flex Packaging | 1520 | 14.5 | 105 | |
| JSI Store Fixtures | 358 | 13 | 28 | |
| | | | | |
| From Data Above | Average kVA/Acre | | 61.75 | |
| | Max kVA/Acre | | 105 | |
| | Min kVA/Acre | | 28 | |
| | | | | |
| Acres Available | 152.6 | | | |
| Est Load at Average kVA/Acre | 9423 | kVA | | |
| Est Load at Max kVA/Acre | 16023 | kVA | | |
| Est Load at Min kVA/Acre | 4273 | kVA | | |
| Est Load at 47 kVA/Acre | **7172** | kVA | Value Used--Average of RM ATV, Liberty Safe, & JSI | |
| | | | | |
| Growth on 710,730 in Forecast | 906 | kVA | | |
| Growth to add = | 6266 | kVA | (uses row 18, 7,172 kVA) | |
| Add in '25 | 0 | kVA | 0 | kW |
| Add in '27 | 1671 | kVA | 1587 | kW |
| Add in '29 | 2506 | kVA | 2381 | kW |
| Add in '33 | 2089 | kVA | 1984 | kW |



# 10. APPENDIX D: PROJECT COST ESTIMATE TABLES

## Project 1:

| Underground & Overhead Costs per 100 ft or 1 unit<br>Switch 610 to 510 | Quantity<br>Unit Qty. | <br>Unit Meas. | Labor Cost<br>Hours per Unit | <br>Total Hours | <br>Total Cost | Material Cost<br>Cost per unit | <br>total cost | Total<br>Unit Cost |
|---|---|---|---|---|---|---|---|---|
| **Underground Primary Cable Installation** | | | | | | | | |
| 3-Phase 15 kV Cable (1100 Al w/1/6 Con. Neutral) | 0 | CKT FT | 0.040 | 0 | $ - | $ 50.00 | $ - | $ - |
| **Trenching** | | | | | | | | |
| Utility Trench for Single Conduit - Good Soil | 0 | LF | 0.070 | 0 | $ - | $ - | $ - | $ - |
| **Conduit Installation** | | | | | | | | |
| New 6" PVC Conduit Installation | 0 | LF | 0.040 | 0 | $ - | $ 16.00 | $ - | $ - |
| **Switchgear Installation & Equipment** | | | | | | | | |
| Box Pad Base for - Three Phase Switch PME Switchgear | 0 | EA | 5.000 | 0 | $ - | $ 1,750.00 | $ - | $ - |
| PME-9 Switchgear (2-600 Amp Sw. & 2-200 Amp Fused) | 0 | EA | 32.000 | 0 | $ - | $ 18,000.00 | $ - | $ - |
| **Overhead** | | | | | | | | |
| 45' CL 2 Pole | 1 | EA | 8.500 | 8.5 | $ 606.31 | $ 1,800.00 | $ 1,800.00 | $ 2,406.31 |
| Guy & Anchor | 0 | EA | 4.250 | 0 | $ - | $ 275.00 | $ - | $ - |
| Three Phase Primary Tangent Pole Top Assembly | 0 | EA | 5.500 | 0 | $ - | $ 475.00 | $ - | $ - |
| Three Phase Primary Single Deadend Pole Top Assembly | 1 | EA | 6.000 | 6 | $ 427.98 | $ 775.00 | $ 775.00 | $ 1,202.98 |
| Three Phase Primary Conductor (477 kcmil ACSR) | 0 | CKT FT | 0.044 | 0 | $ - | $ 16.00 | $ - | $ - |
| Three Phase - Primary Riser | 0 | EA | 12.500 | 0 | $ - | $ 1,375.00 | $ - | $ - |
| Three Phase - Gang Operated Air Break Switch | 1 | EA | 12.000 | 12 | $ 855.96 | $ 7,200.00 | $ 7,200.00 | $ 8,055.96 |
| | | | | | | | **Total** | **$ 11,665.25** |

**Subtotals**

| | | | |
|---|---|---|---|
| Total Hours | 26.5 | Subtotal Material | $ 9,775.00 |
| Avg. Labor Rate | $ 71.33 | Subtotal Labor | $ 1,890.25 |
| Sales Tax Material | 0.00% | Subtotal Tax | $ - |
| | | Subtotal Labor, Material & Tax | $ 11,665.25 |
| Equipment & Trucks | $ 40.00 | Subtotal Equipment & Trucks | $ 1,060.00 |
| Contingency | 15.00% | Subtotal Contingency | $ 1,908.79 |
| Engineering | 8.00% | Subtotal Engineering | $ 933.22 |
| | | Total Budgetary Estimate | $ 15,567.25 |

## Project 2:

| South Substation | Quantity | | Labor Cost | | | Material Cost | | Total |
|---|---|---|---|---|---|---|---|---|
| | Unit Qty. | Unit Meas. | Hours per Unit | Total Hours | Total Cost | Cost per unit | total cost | Unit Cost |
| **Substation Equipment and Installation** | | | | | | | | |
| 46 kV -12.47 kV 12/20 MVA Tansformer | 1 | EA | 100.000 | 100 | $ 7,133.00 | $ 1,500,000.00 | $ 1,500,000.00 | $ 1,507,133.00 |
| 46 kV High Side Breaker | 1 | EA | 20.000 | 20 | $ 1,426.60 | $ 67,600.00 | $ 67,600.00 | $ 69,026.60 |
| 46 kV GOAB Switch | 1 | EA | 24.000 | 24 | $ 1,711.92 | $ 14,560.00 | $ 14,560.00 | $ 16,271.92 |
| 46 kV Relaying VT | 3 | EA | 6.000 | 18 | $ 1,283.94 | $ 9,880.00 | $ 29,640.00 | $ 30,923.94 |
| 15 kV GOAB Switch | 1 | EA | 16.000 | 16 | $ 1,141.28 | $ 5,620.00 | $ 5,620.00 | $ 6,761.28 |
| 15 kV Recloser | 4 | EA | 16.000 | 64 | $ 4,565.12 | $ 8,530.00 | $ 34,120.00 | $ 38,685.12 |
| 15 kV VT | 4 | EA | 4.000 | 16 | $ 1,141.28 | $ 2,080.00 | $ 8,320.00 | $ 9,461.28 |
| 15 kV 1 phase fused disconnect | 16 | EA | 2.000 | 32 | $ 2,282.56 | $ 5,720.00 | $ 91,520.00 | $ 93,802.56 |
| 15 kV 1 phase Hookstick Switch | 24 | EA | 2.000 | 48 | $ 3,423.84 | $ 1,250.00 | $ 30,000.00 | $ 33,423.84 |
| Metering/Relaying | 1 | EA | 120.000 | 120 | $ 8,559.60 | $ 95,000.00 | $ 95,000.00 | $ 103,559.60 |
| Steel Structures | 1 | EA | 266.000 | 266 | $ 18,973.78 | $ 370,000.00 | $ 370,000.00 | $ 388,973.78 |
| Concrete Foundations | 1 | EA | 212.000 | 212 | $ 15,121.96 | $ 429,700.00 | $ 429,700.00 | $ 444,821.96 |
| Substation Bus & Material | 1 | EA | 596.000 | 596 | $ 42,512.68 | $ 227,000.00 | $ 227,000.00 | $ 269,512.68 |
| Substation Conduit & Cable | 1 | EA | 487.000 | 487 | $ 34,737.71 | $ 119,100.00 | $ 119,100.00 | $ 153,837.71 |
| Substation Grounding | 1 | EA | 160.000 | 160 | $ 11,412.80 | $ 26,000.00 | $ 26,000.00 | $ 37,412.80 |
| Substation Site Work | 500 | CUYD | 0.100 | 50 | $ 3,566.50 | $ 60.00 | $ 30,000.00 | $ 33,566.50 |
| Substation SCADA & Communications | 1 | EA | 48.000 | 48 | $ 3,423.84 | $ 15,600.00 | $ 15,600.00 | $ 19,023.84 |
| 15 kV Distribution Feeders | 4 | EA | 180.000 | 720 | $ 51,357.60 | $ 166,950.00 | $ 667,800.00 | $ 719,157.60 |
| Substation Testing & Commissioning | 1 | EA | 375.000 | 375 | $ 26,748.75 | $ 3,900.00 | $ 3,900.00 | $ 30,648.75 |
| **Underground Primary Cable Installation** | | | | | | | | |
| 3-Phase 15 kV Cable (1100 Al w/1/6 Con. Neutral) | 3,400 | CKT FT | 0.040 | 136 | $ 9,700.88 | $ 50.00 | $ 170,000.00 | $ 179,700.88 |
| **Trenching** | | | | | | | | |
| Utility Trench for Single Conduit - Good Soil | 3,000 | LF | 0.070 | 210 | $ 14,979.30 | $ - | $ - | $ 14,979.30 |
| **Conduit Installation** | | | | | | | | |
| New 6" PVC Conduit Installation | 3,000 | LF | 0.040 | 120 | $ 8,559.60 | $ 16.00 | $ 48,000.00 | $ 56,559.60 |
| **Switchgear Installation & Equipment** | | | | | | | | |
| Box Pad Base for - Three Phase Switch PME Switchgear | 4 | EA | 5.000 | 20 | $ 1,426.60 | $ 1,750.00 | $ 7,000.00 | $ 8,426.60 |
| PME-9 Switchgear (2-600 Amp Sw. & 2-200 Amp Fused) | 4 | EA | 32.000 | 128 | $ 9,130.24 | $ 18,000.00 | $ 72,000.00 | $ 81,130.24 |
| **Overhead** | | | | | | | | |
| 45' CL 2 Pole | 4 | EA | 8.500 | 34 | $ 2,425.22 | $ 1,800.00 | $ 7,200.00 | $ 9,625.22 |
| Guy & Anchor | 4 | EA | 4.250 | 17 | $ 1,212.61 | $ 275.00 | $ 1,100.00 | $ 2,312.61 |
| Three Phase Primary Tangent Pole Top Assembly | 0 | EA | 5.500 | 0 | $ - | $ 475.00 | $ - | $ - |
| Three Phase Primary Single Deadend Pole Top Assembly | 4 | EA | 6.000 | 24 | $ 1,711.92 | $ 775.00 | $ 3,100.00 | $ 4,811.92 |
| Three Phase Primary Conductor (477 kcmil ACSR) | 0 | CKT FT | 0.044 | 0 | $ - | $ 16.00 | $ - | $ - |
| Three Phase - Primary Riser | 4 | EA | 12.500 | 50 | $ 3,566.50 | $ 1,375.00 | $ 5,500.00 | $ 9,066.50 |
| | | | | | | | Total | $ 4,372,617.63 |

**Subtotals**

| | | | | |
|---|---|---|---|---|
| | | Total Hours: 4111 | Subtotal Material | $ 4,079,380.00 |
| Avg. Labor Rate | $ 71.33 | Subtotal Labor: $ 293,237.63 | | |
| Sales Tax Material | 0.00% | | Subtotal Tax | $ - |
| | | | Subtotal Labor, Material & Tax | $ 4,372,617.63 |
| Equipment & Trucks | $ 40.00 | | Subtotal Equipment & Trucks | $ 164,440.00 |
| Contingency | 15.00% | | Subtotal Contingency | $ 680,558.64 |
| Engineering | 8.00% | | Subtotal Engineering | $ 349,809.41 |
| | | | Total Budgetary Estimate | $ 5,567,425.68 |
| | | | Plus T-Line | $ 2,800,000.00 |
| | | | | $ 8,367,425.68 |

## Project 3:

| North/Arrowhead Substation | Quantity | | Labor Cost | | | Material Cost | | Total |
|---|---|---|---|---|---|---|---|---|
| | Unit Qty. | Unit Meas. | Hours per Unit | Total Hours | Total Cost | Cost per unit | total cost | Unit Cost |
| **Substation Equipment and Installation** | | | | | | | | |
| 46 kV -12.47 kV 12/20 MVA Tansformer | 1 | EA | 100.000 | 100 | $ 7,133.00 | $ 1,500,000.00 | $ 1,500,000.00 | $ 1,507,133.00 |
| 46 kV High Side Breaker | 1 | EA | 20.000 | 20 | $ 1,426.60 | $ 67,600.00 | $ 67,600.00 | $ 69,026.60 |
| 46 kV GOAB Switch | 1 | EA | 24.000 | 24 | $ 1,711.92 | $ 14,560.00 | $ 14,560.00 | $ 16,271.92 |
| 46 kV Relaying VT | 3 | EA | 6.000 | 18 | $ 1,283.94 | $ 9,880.00 | $ 29,640.00 | $ 30,923.94 |
| 15 kV GOAB Switch | 1 | EA | 16.000 | 16 | $ 1,141.28 | $ 5,620.00 | $ 5,620.00 | $ 6,761.28 |
| 15 kV Recloser | 4 | EA | 16.000 | 64 | $ 4,565.12 | $ 8,530.00 | $ 34,120.00 | $ 38,685.12 |
| 15 kV VT | 4 | EA | 4.000 | 16 | $ 1,141.28 | $ 2,080.00 | $ 8,320.00 | $ 9,461.28 |
| 15 kV 1 phase fused disconnect | 16 | EA | 2.000 | 32 | $ 2,282.56 | $ 5,720.00 | $ 91,520.00 | $ 93,802.56 |
| 15 kV 1 phase Hookstick Switch | 24 | EA | 2.000 | 48 | $ 3,423.84 | $ 1,250.00 | $ 30,000.00 | $ 33,423.84 |
| Metering/Relaying | 1 | EA | 120.000 | 120 | $ 8,559.60 | $ 95,000.00 | $ 95,000.00 | $ 103,559.60 |
| Steel Structures | 1 | EA | 266.000 | 266 | $ 18,973.78 | $ 370,000.00 | $ 370,000.00 | $ 388,973.78 |
| Concrete Foundations | 1 | EA | 212.000 | 212 | $ 15,121.96 | $ 429,700.00 | $ 429,700.00 | $ 444,821.96 |
| Substation Bus & Material | 1 | EA | 596.000 | 596 | $ 42,512.68 | $ 227,000.00 | $ 227,000.00 | $ 269,512.68 |
| Substation Conduit & Cable | 1 | EA | 487.000 | 487 | $ 34,737.71 | $ 119,100.00 | $ 119,100.00 | $ 153,837.71 |
| Substation Grounding | 1 | EA | 160.000 | 160 | $ 11,412.80 | $ 26,000.00 | $ 26,000.00 | $ 37,412.80 |
| Substation Site Work | 500 | CUYD | 0.100 | 50 | $ 3,566.50 | $ 60.00 | $ 30,000.00 | $ 33,566.50 |
| Substation SCADA & Communications | 1 | EA | 48.000 | 48 | $ 3,423.84 | $ 15,600.00 | $ 15,600.00 | $ 19,023.84 |
| 15 kV Distribution Feeders | 4 | EA | 180.000 | 720 | $ 51,357.60 | $ 166,950.00 | $ 667,800.00 | $ 719,157.60 |
| Substation Testing & Commissioning | 1 | EA | 375.000 | 375 | $ 26,748.75 | $ 3,900.00 | $ 3,900.00 | $ 30,648.75 |
| **Underground Primary Cable Installation** | | | | | | | | |
| 3-Phase 15 kV Cable (1100 Al w/1/6 Con. Neutral) | 3,400 | CKT FT | 0.040 | 136 | $ 9,700.88 | $ 50.00 | $ 170,000.00 | $ 179,700.88 |
| **Trenching** | | | | | | | | |
| Utility Trench for Single Conduit - Good Soil | 3,000 | LF | 0.070 | 210 | $ 14,979.30 | $ - | $ - | $ 14,979.30 |
| **Conduit Installation** | | | | | | | | |
| New 6" PVC Conduit Installation | 3,000 | LF | 0.040 | 120 | $ 8,559.60 | $ 16.00 | $ 48,000.00 | $ 56,559.60 |
| **Switchgear Installation & Equipment** | | | | | | | | |
| Box Pad Base for - Three Phase Switch PME Switchgear | 4 | EA | 5.000 | 20 | $ 1,426.60 | $ 1,750.00 | $ 7,000.00 | $ 8,426.60 |
| PME-9 Switchgear (2-600 Amp Sw. & 2-200 Amp Fused) | 4 | EA | 32.000 | 128 | $ 9,130.24 | $ 18,000.00 | $ 72,000.00 | $ 81,130.24 |
| **Overhead** | | | | | | | | |
| 45' CL 2 Pole | 4 | EA | 8.500 | 34 | $ 2,425.22 | $ 1,800.00 | $ 7,200.00 | $ 9,625.22 |
| Guy & Anchor | 4 | EA | 4.250 | 17 | $ 1,212.61 | $ 275.00 | $ 1,100.00 | $ 2,312.61 |
| Three Phase Primary Tangent Pole Top Assembly | 0 | EA | 5.500 | 0 | $ - | $ 475.00 | $ - | $ - |
| Three Phase Primary Single Deadend Pole Top Assembly | 4 | EA | 6.000 | 24 | $ 1,711.92 | $ 775.00 | $ 3,100.00 | $ 4,811.92 |
| Three Phase Primary Conductor (477 kcmil ACSR) | 0 | CKT FT | 0.044 | 0 | $ - | $ 16.00 | $ - | $ - |
| Three Phase - Primary Riser | 4 | EA | 12.500 | 50 | $ 3,566.50 | $ 1,375.00 | $ 5,500.00 | $ 9,066.50 |
| | | | | | | | **Total** | **$ 4,372,617.63** |

**Subtotals**

| | | | | |
|---|---|---|---|---|
| | Total Hours | 4111 | Subtotal Material | $ 4,079,380.00 |
| Avg. Labor Rate | $ 71.33 | | | |
| | Subtotal Labor | $ 293,237.63 | | |
| Sales Tax Material | 0.00% | | Subtotal Tax | $ - |
| | | | Subtotal Labor, Material & Tax | $ 4,372,617.63 |
| Equipment & Trucks | $ 40.00 | | Subtotal Equipment & Trucks | $ 164,440.00 |
| Contingency | 15.00% | | Subtotal Contingency | $ 680,558.64 |
| Engineering | 8.00% | | Subtotal Engineering | $ 349,809.41 |
| | | | Total Budgetary Estimate | $ 5,567,425.68 |

| | |
|---|---|
| Plus T-Line | $ 682,746.36 |
| | $ 6,250,172.05 |

## Project 4:

| Underground & Overhead Costs per 100 ft or 1 unit<br>Project 4 Tie 510 to 730 | Quantity<br>Unit Qty. | <br>Unit Meas. | Labor Cost<br>Hours per Unit | <br>Total Hours | <br>Total Cost | Material Cost<br>Cost per unit | <br>total cost | Total<br>Unit Cost |
|---|---|---|---|---|---|---|---|---|
| **Underground Primary Cable Installation** | | | | | | | | |
| 3-Phase 15 kV Cable (1100 Al w/1/6 Con. Neutral) | 1,450 | CKT FT | 0.040 | 58 | $ 4,137.14 | $ 50.00 | $ 72,500.00 | $ 76,637.14 |
| **Trenching** | | | | | | | | |
| Utility Trench for Single Conduit - Good Soil | 1,450 | LF | 0.070 | 101.5 | $ 7,240.00 | $ - | $ - | $ 7,240.00 |
| **Conduit Installation** | | | | | | | | |
| New 6" PVC Conduit Installation | 1,450 | LF | 0.040 | 58 | $ 4,137.14 | $ 16.00 | $ 23,200.00 | $ 27,337.14 |
| **Switchgear Installation & Equipment** | | | | | | | | |
| Box Pad Base for - Three Phase Switch PME Switchgear | 2 | EA | 5.000 | 10 | $ 713.30 | $ 1,750.00 | $ 3,500.00 | $ 4,213.30 |
| PME-9 Switchgear (2-600 Amp Sw. & 2-200 Amp Fused) | 2 | EA | 32.000 | 64 | $ 4,565.12 | $ 18,000.00 | $ 36,000.00 | $ 40,565.12 |
| **Overhead** | | | | | | | | |
| 45' CL 2 Pole | 0 | EA | 8.500 | 0 | $ - | $ 1,800.00 | $ - | $ - |
| Guy & Anchor | 0 | EA | 4.250 | 0 | $ - | $ 275.00 | $ - | $ - |
| Three Phase Primary Tangent Pole Top Assembly | 0 | EA | 5.500 | 0 | $ - | $ 475.00 | $ - | $ - |
| Three Phase Primary Single Deadend Pole Top Assembly | 0 | EA | 6.000 | 0 | $ - | $ 775.00 | $ - | $ - |
| Three Phase Primary Conductor (477 kcmil ACSR) | 0 | CKT FT | 0.044 | 0 | $ - | $ 16.00 | $ - | $ - |
| Three Phase - Primary Riser | 0 | EA | 12.500 | 0 | $ - | $ 1,375.00 | $ - | $ - |
| | | | | | | | **Total** | **$ 155,992.70** |

**Subtotals**

| | | | |
|---|---|---|---|
| | | Total Hours | 291.5 |
| | | Subtotal Material | $ 135,200.00 |
| Avg. Labor Rate | $ 71.33 | Subtotal Labor | $ 20,792.70 |
| Sales Tax Material | 0.00% | Subtotal Tax | $ - |
| | | Subtotal Labor, Material & Tax | $ 155,992.70 |
| Equipment & Trucks | $ 40.00 | Subtotal Equipment & Trucks | $ 11,660.00 |
| Contingency | 15.00% | Subtotal Contingency | $ 25,147.90 |
| Engineering | 8.00% | Subtotal Engineering | $ 12,479.42 |
| | | Total Budgetary Estimate | $ 205,280.01 |

## Project 5:

| Underground & Overhead Costs per 100 ft or 1 unit | Quantity | | Labor Cost | | | Material Cost | | Total |
|---|---|---|---|---|---|---|---|---|
| Project 5 510-610 I-15 Xing | Unit Qty. | Unit Meas. | Hours per Unit | Total Hours | Total Cost | Cost per unit | total cost | Unit Cost |
| **Underground Primary Cable Installation** | | | | | | | | |
| 3-Phase 15 kV Cable (1100 Al w/1/6 Con. Neutral) | 0 | CKT FT | 0.040 | 0 | $ - | $ 50.00 | $ - | $ - |
| **Trenching** | | | | | | | | |
| Utility Trench for Single Conduit - Good Soil | 0 | LF | 0.070 | 0 | $ - | $ - | $ - | $ - |
| **Conduit Installation** | | | | | | | | |
| New 6" PVC Conduit Installation | 0 | LF | 0.040 | 0 | $ - | $ 16.00 | $ - | $ - |
| **Switchgear Installation & Equipment** | | | | | | | | |
| Box Pad Base for - Three Phase Switch PME Switchgear | 0 | EA | 5.000 | 0 | $ - | $ 1,750.00 | $ - | $ - |
| PME-9 Switchgear (2-600 Amp Sw. & 2-200 Amp Fused) | 0 | EA | 32.000 | 0 | $ - | $ 18,000.00 | $ - | $ - |
| **Overhead** | | | | | | | | |
| 45' CL 2 Pole | 7 | EA | 8.500 | 59.5 | $ 4,244.14 | $ 1,800.00 | $ 12,600.00 | $ 16,844.14 |
| Guy & Anchor | 2 | EA | 4.250 | 8.5 | $ 606.31 | $ 275.00 | $ 550.00 | $ 1,156.31 |
| Three Phase Primary Tangent Pole Top Assembly | 5 | EA | 5.500 | 27.5 | $ 1,961.58 | $ 475.00 | $ 2,375.00 | $ 4,336.58 |
| Three Phase Primary Single Deadend Pole Top Assembly | 2 | EA | 6.000 | 12 | $ 855.96 | $ 775.00 | $ 1,550.00 | $ 2,405.96 |
| Three Phase Primary Conductor (477 kcmil ACSR) | 1525 | CKT FT | 0.044 | 67.1 | $ 4,786.24 | $ 16.00 | $ 24,400.00 | $ 29,186.24 |
| Three Phase - Primary Riser | 0 | EA | 12.500 | 0 | $ - | $ 1,375.00 | $ - | $ - |
| | | | | | | | **Total** | **$ 53,929.22** |

**Subtotals**

| | |
|---|---|
| Total Hours | 174.6 |
| Subtotal Material | $ 41,475.00 |
| Avg. Labor Rate | $ 71.33 |
| Subtotal Labor | $ 12,454.22 |
| Sales Tax Material | 0.00% |
| Subtotal Tax | $ - |
| Subtotal Labor, Material & Tax | $ 53,929.22 |
| Equipment & Trucks | $ 40.00 |
| Contingency | 15.00% |
| Engineering | 8.00% |
| Subtotal Equipment & Trucks | $ 6,984.00 |
| Subtotal Contingency | $ 9,136.98 |
| Subtotal Engineering | $ 4,314.34 |
| Total Budgetary Estimate | $ 74,364.54 |

## Project 6:

| Underground & Overhead Costs per 100 ft or 1 unit | Quantity | | Labor Cost | | | Material Cost | | Total |
|---|---|---|---|---|---|---|---|---|
| Project 6 South Sub tie to 800 South--Underbuilt on transmission li | Unit Qty. | Unit Meas. | Hours per Unit | Total Hours | Total Cost | Cost per unit | total cost | Unit Cost |
| | | | **Underground Primary Cable Installation** | | | | | |
| 3-Phase 15 kV Cable (1100 Al w/1/6 Con. Neutral) | 0 | CKT FT | 0.040 | 0 | $ - | $ 50.00 | $ - | $ - |
| | | | **Trenching** | | | | | |
| Utility Trench for Single Conduit - Good Soil | 0 | LF | 0.070 | 0 | $ - | $ - | $ - | $ - |
| | | | **Conduit Installation** | | | | | |
| New 6" PVC Conduit Installation | 0 | LF | 0.040 | 0 | $ - | $ 16.00 | $ - | $ - |
| | | | **Switchgear Installation & Equipment** | | | | | |
| Box Pad Base for - Three Phase Switch PME Switchgear | 0 | EA | 5.000 | 0 | $ - | $ 1,750.00 | $ - | $ - |
| PME-9 Switchgear (2-600 Amp Sw. & 2-200 Amp Fused) | 0 | EA | 32.000 | 0 | $ - | $ 18,000.00 | $ - | $ - |
| | | | **Overhead** | | | | | |
| 45' CL 2 Pole | 2 | EA | 8.500 | 17 | $ 1,212.61 | $ 1,800.00 | $ 3,600.00 | $ 4,812.61 |
| Guy & Anchor | 3 | EA | 4.250 | 12.75 | $ 909.46 | $ 275.00 | $ 825.00 | $ 1,734.46 |
| Three Phase Primary Tangent Pole Top Assembly | 25 | EA | 5.500 | 137.5 | $ 9,807.88 | $ 475.00 | $ 11,875.00 | $ 21,682.88 |
| Three Phase Primary Single Deadend Pole Top Assembly | 4 | EA | 6.000 | 24 | $ 1,711.92 | $ 775.00 | $ 3,100.00 | $ 4,811.92 |
| Three Phase Primary Conductor (477 kcmil ACSR) | 7350 | CKT FT | 0.044 | 323.4 | $ 23,068.12 | $ 16.00 | $ 117,600.00 | $ 140,668.12 |
| Three Phase - Primary Riser | 2 | EA | 12.500 | 25 | $ 1,783.25 | $ 1,375.00 | $ 2,750.00 | $ 4,533.25 |
| | | | | | | | **Total** | **$ 178,243.23** |

**Subtotals**

| | | | | | |
|---|---|---|---|---|---|
| | | Total Hours | 539.65 | Subtotal Material | $ 139,750.00 |
| Avg. Labor Rate | $ 71.33 | | | | |
| | | Subtotal Labor | $ 38,493.23 | | |
| Sales Tax Material | 0.00% | | | Subtotal Tax | $ - |
| | | | | Subtotal Labor, Material & Tax | $ 178,243.23 |
| Equipment & Trucks | $ 40.00 | | | Subtotal Equipment & Trucks | $ 21,586.00 |
| Contingency | 15.00% | | | Subtotal Contingency | $ 29,974.39 |
| Engineering | 8.00% | | | Subtotal Engineering | $ 14,259.46 |
| | | | | Total Budgetary Estimate | $ 244,063.08 |

## Project 7:

| Underground & Overhead Costs per 100 ft or 1 unit | Quantity | | Labor Cost | | | Material Cost | | Total |
|---|---|---|---|---|---|---|---|---|
| Project 7 Strong tie feeders 710 to 320 | Unit Qty. | Unit Meas. | Hours per Unit | Total Hours | Total Cost | Cost per unit | total cost | Unit Cost |
| **Underground Primary Cable Installation** | | | | | | | | |
| 3-Phase 15 kV Cable (1100 Al w/1/6 Con. Neutral) | 850 | CKT FT | 0.040 | 34 | $ 2,425.22 | $ 50.00 | $ 42,500.00 | $ 44,925.22 |
| **Trenching** | | | | | | | | |
| Utility Trench for Single Conduit - Good Soil | 850 | LF | 0.070 | 59.5 | $ 4,244.14 | $ - | $ - | $ 4,244.14 |
| **Conduit Installation** | | | | | | | | |
| New 6" PVC Conduit Installation | 850 | LF | 0.040 | 34 | $ 2,425.22 | $ 16.00 | $ 13,600.00 | $ 16,025.22 |
| **Switchgear Installation & Equipment** | | | | | | | | |
| Box Pad Base for - Three Phase Switch PME Switchgear | 1 | EA | 5.000 | 5 | $ 356.65 | $ 1,750.00 | $ 1,750.00 | $ 2,106.65 |
| PME-9 Switchgear (2-600 Amp Sw. & 2-200 Amp Fused) | 1 | EA | 32.000 | 32 | $ 2,282.56 | $ 18,000.00 | $ 18,000.00 | $ 20,282.56 |
| **Overhead** | | | | | | | | |
| 45' CL 2 Pole | 21 | EA | 8.500 | 178.5 | $ 12,732.41 | $ 1,800.00 | $ 37,800.00 | $ 50,532.41 |
| Guy & Anchor | 6 | EA | 4.250 | 25.5 | $ 1,818.92 | $ 275.00 | $ 1,650.00 | $ 3,468.92 |
| Three Phase Primary Tangent Pole Top Assembly | 24 | EA | 5.500 | 132 | $ 9,415.56 | $ 475.00 | $ 11,400.00 | $ 20,815.56 |
| Three Phase Primary Single Deadend Pole Top Assembly | 6 | EA | 6.000 | 36 | $ 2,567.88 | $ 775.00 | $ 4,650.00 | $ 7,217.88 |
| Three Phase Primary Conductor (477 kcmil ACSR) | 4760 | CKT FT | 0.044 | 209.44 | $ 14,939.36 | $ 16.00 | $ 76,160.00 | $ 91,099.36 |
| Three Phase - Primary Riser | 4 | EA | 12.500 | 50 | $ 3,566.50 | $ 1,375.00 | $ 5,500.00 | $ 9,066.50 |
| | | | | | | | **Total** | **$ 269,784.40** |

**Subtotals**

| | | | |
|---|---|---|---|
| | | Total Hours | 795.94 |
| | | Subtotal Material | $ 213,010.00 |
| Avg. Labor Rate | $ 71.33 | Subtotal Labor | $ 56,774.40 |
| Sales Tax Material | 0.00% | Subtotal Tax | $ - |
| | | Subtotal Labor, Material & Tax | $ 269,784.40 |
| Equipment & Trucks | $ 40.00 | Subtotal Equipment & Trucks | $ 31,837.60 |
| Contingency | 15.00% | Subtotal Contingency | $ 45,243.30 |
| Engineering | 8.00% | Subtotal Engineering | $ 21,582.75 |
| | | Total Budgetary Estimate | $ 368,448.05 |

## Project 8:

| 46 kV Transmission Line to South Sub<br>Project 8 46 kV transmission line loop (west side) | Quantity<br>Unit Qty. | Unit Meas. | Labor Cost<br>Hours per Unit | Total Hours | Total Cost | Material Cost<br>Cost per unit | total cost | Total<br>Unit Cost |
|---|---|---|---|---|---|---|---|---|
| **Underground Primary Cable Installation** | | | | | | | | |
| 3-Phase 15 kV Cable (1100 Al w/1/6 Con. Neutral) | 0 | CKT FT | 0.040 | 0 | $ - | $ 50.00 | $ - | $ - |
| **Trenching** | | | | | | | | |
| Utility Trench for Single Conduit - Good Soil | 0 | LF | 0.070 | 0 | $ - | $ - | $ - | $ - |
| **Conduit Installation** | | | | | | | | |
| New 6" PVC Conduit Installation | 0 | LF | 0.040 | 0 | $ - | $ 16.00 | $ - | $ - |
| **Switchgear Installation & Equipment** | | | | | | | | |
| Box Pad Base for - Three Phase Switch PME Switchgear | 0 | EA | 5.000 | 0 | $ - | $ 1,750.00 | $ - | $ - |
| PME-9 Switchgear (2-600 Amp Sw. & 2-200 Amp Fused) | 0 | EA | 32.000 | 0 | $ - | $ 18,000.00 | $ - | $ - |
| **Overhead** | | | | | | | | |
| Steel Transmission Pole incl. Eng. & Foundation | 3 | EA | 34.000 | 102 | $ 7,275.66 | $ 175,000.00 | $ 525,000.00 | $ 532,275.66 |
| 70' CL H1 Pole | 75 | EA | 17.000 | 1275 | $ 90,945.75 | $ 5,000.00 | $ 375,000.00 | $ 465,945.75 |
| 46 kV insulators | 225 | EA | 2.000 | 450 | $ 32,098.50 | $ 200.00 | $ 45,000.00 | $ 77,098.50 |
| Guy & Anchor | 0 | EA | 4.250 | 0 | $ - | $ 275.00 | $ - | $ - |
| Three Phase Primary Tangent Pole Top Assembly | 75 | EA | 5.500 | 412.5 | $ 29,423.63 | $ 475.00 | $ 35,625.00 | $ 65,048.63 |
| Three Phase Primary Single Deadend Pole Top Assembly | 5 | EA | 6.000 | 30 | $ 2,139.90 | $ 775.00 | $ 3,875.00 | $ 6,014.90 |
| Three Phase Primary Conductor (795 ACSR) | 21000 | CKT FT | 0.044 | 924 | $ 65,908.92 | $ 30.11 | $ 632,310.00 | $ 698,218.92 |
| 46 kV switches | 2 | EA | 12.500 | 25 | $ 1,783.25 | $ 12,000.00 | $ 24,000.00 | $ 25,783.25 |
| | | | | | | | **Total** | **$ 1,870,385.61** |

**Subtotals**

| | | | | |
|---|---|---|---|---|
| | | Total Hours 3218.5 | Subtotal Material | $ 1,640,810.00 |
| Avg. Labor Rate | $ 71.33 | Subtotal Labor $ 229,575.61 | | |
| Sales Tax Material | 0.00% | | Subtotal Tax | $ - |
| | | | Subtotal Labor, Material & Tax | $ 1,870,385.61 |
| Equipment & Trucks | $ 40.00 | | Subtotal Equipment & Trucks | $ 128,740.00 |
| Contingency | 15.00% | | Subtotal Contingency | $ 299,868.84 |
| Engineering | 8.00% | | Subtotal Engineering | $ 149,630.85 |
| | | | Total Budgetary Estimate | $ 2,448,625.29 |

## Project 9:

| Underground & Overhead Costs per 100 ft or 1 unit | Quantity | | Labor Cost | | | Material Cost | | Total |
|---|---|---|---|---|---|---|---|---|
| Project 9 South Sub feeder 810 tie to 510/730 | Unit Qty. | Unit Meas. | Hours per Unit | Total Hours | Total Cost | Cost per unit | total cost | Unit Cost |
| **Underground Primary Cable Installation** | | | | | | | | |
| 3-Phase 15 kV Cable (1100 Al w/1/6 Con. Neutral) | 0 | CKT FT | 0.040 | 0 | $ - | $ 50.00 | $ - | $ - |
| **Trenching** | | | | | | | | |
| Utility Trench for Single Conduit - Good Soil | 0 | LF | 0.070 | 0 | $ - | $ - | $ - | $ - |
| **Conduit Installation** | | | | | | | | |
| New 6" PVC Conduit Installation | 0 | LF | 0.040 | 0 | $ - | $ 16.00 | $ - | $ - |
| **Switchgear Installation & Equipment** | | | | | | | | |
| Box Pad Base for - Three Phase Switch PME Switchgear | 1 | EA | 5.000 | 5 | $ 356.65 | $ 1,750.00 | $ 1,750.00 | $ 2,106.65 |
| PME-9 Switchgear (2-600 Amp Sw. & 2-200 Amp Fused) | 1 | EA | 32.000 | 32 | $ 2,282.56 | $ 18,000.00 | $ 18,000.00 | $ 20,282.56 |
| **Overhead** | | | | | | | | |
| 45' CL 2 Pole | 53 | EA | 8.500 | 450.5 | $ 32,134.17 | $ 1,800.00 | $ 95,400.00 | $ 127,534.17 |
| Guy & Anchor | 8 | EA | 4.250 | 34 | $ 2,425.22 | $ 275.00 | $ 2,200.00 | $ 4,625.22 |
| Three Phase Primary Tangent Pole Top Assembly | 48 | EA | 5.500 | 264 | $ 18,831.12 | $ 475.00 | $ 22,800.00 | $ 41,631.12 |
| Three Phase Primary Single Deadend Pole Top Assembly | 8 | EA | 6.000 | 48 | $ 3,423.84 | $ 775.00 | $ 6,200.00 | $ 9,623.84 |
| Three Phase Primary Conductor (477 kcmil ACSR) | 12900 | CKT FT | 0.044 | 567.6 | $ 40,486.91 | $ 16.00 | $ 206,400.00 | $ 246,886.91 |
| Three Phase - Primary Riser | 2 | EA | 12.500 | 25 | $ 1,783.25 | $ 1,375.00 | $ 2,750.00 | $ 4,533.25 |
| | | | | | | | **Total** | **$ 457,223.71** |

**Subtotals**

| | | | |
|---|---|---|---|
| | | Total Hours | 1426.1 |
| | | Subtotal Material | $ 355,500.00 |
| Avg. Labor Rate | $ 71.33 | Subtotal Labor | $ 101,723.71 |
| Sales Tax Material | 0.00% | Subtotal Tax | $ - |
| | | Subtotal Labor, Material & Tax | $ 457,223.71 |
| Equipment & Trucks | $ 40.00 | Subtotal Equipment & Trucks | $ 57,044.00 |
| Contingency | 15.00% | Subtotal Contingency | $ 77,140.16 |
| Engineering | 8.00% | Subtotal Engineering | $ 36,577.90 |
| | | Total Budgetary Estimate | $ 627,985.77 |

## Project 10:

| Underground & Overhead Costs per 100 ft or 1 unit | Quantity | | Labor Cost | | | Material Cost | | Total |
|---|---|---|---|---|---|---|---|---|
| Project 10 Recond/Rebuild 330 main line | Unit Qty. | Unit Meas. | Hours per Unit | Total Hours | Total Cost | Cost per unit | total cost | Unit Cost |
| **Underground Primary Cable Installation** | | | | | | | | |
| 3-Phase 15 kV Cable (1100 Al w/1/6 Con. Neutral) | 1,960 | CKT FT | 0.040 | 78.4 | $ 5,592.27 | $ 50.00 | $ 98,000.00 | $ 103,592.27 |
| **Trenching** | | | | | | | | |
| Utility Trench for Single Conduit - Good Soil | 1,960 | LF | 0.070 | 137.2 | $ 9,786.48 | $ - | $ - | $ 9,786.48 |
| **Conduit Installation** | | | | | | | | |
| New 6" PVC Conduit Installation | 1,960 | LF | 0.040 | 78.4 | $ 5,592.27 | $ 16.00 | $ 31,360.00 | $ 36,952.27 |
| **Switchgear Installation & Equipment** | | | | | | | | |
| Box Pad Base for - Three Phase Switch PME Switchgear | 2 | EA | 5.000 | 10 | $ 713.30 | $ 1,750.00 | $ 3,500.00 | $ 4,213.30 |
| PME-9 Switchgear (2-600 Amp Sw. & 2-200 Amp Fused) | 2 | EA | 32.000 | 64 | $ 4,565.12 | $ 18,000.00 | $ 36,000.00 | $ 40,565.12 |
| **Overhead** | | | | | | | | |
| 45' CL 2 Pole | 9 | EA | 8.500 | 76.5 | $ 5,456.75 | $ 1,800.00 | $ 16,200.00 | $ 21,656.75 |
| Guy & Anchor | 2 | EA | 4.250 | 8.5 | $ 606.31 | $ 275.00 | $ 550.00 | $ 1,156.31 |
| Three Phase Primary Tangent Pole Top Assembly | 6 | EA | 5.500 | 33 | $ 2,353.89 | $ 475.00 | $ 2,850.00 | $ 5,203.89 |
| Three Phase Primary Single Deadend Pole Top Assembly | 2 | EA | 6.000 | 12 | $ 855.96 | $ 775.00 | $ 1,550.00 | $ 2,405.96 |
| Three Phase Primary Conductor (477 kcmil ACSR) | 980 | CKT FT | 0.044 | 43.12 | $ 3,075.75 | $ 16.00 | $ 15,680.00 | $ 18,755.75 |
| Three Phase - Primary Riser | 1 | EA | 12.500 | 12.5 | $ 891.63 | $ 1,375.00 | $ 1,375.00 | $ 2,266.63 |
| | | | | | | | **Total** | **$ 246,554.71** |
| **Subtotals** | | | | | | | | |
| | | | Total Hours | 553.62 | | Subtotal Material | $ 207,065.00 | |
| Avg. Labor Rate | $ 71.33 | | Subtotal Labor | | $ 39,489.71 | | | |
| Sales Tax Material | 0.00% | | | | | Subtotal Tax | $ - | |
| | | | | | Subtotal Labor, Material & Tax | | | $ 246,554.71 |
| Equipment & Trucks | $ 40.00 | | | | Subtotal Equipment & Trucks | | | $ 22,144.80 |
| Contingency | 15.00% | | | | Subtotal Contingency | | | $ 40,304.93 |
| Engineering | 8.00% | | | | Subtotal Engineering | | | $ 19,724.38 |
| | | | | | Total Budgetary Estimate | | | $ 328,728.82 |

## Project 11:

| **Underground & Overhead Costs per 100 ft or 1 unit** | **Quantity** | | **Labor Cost** | | | **Material Cost** | | **Total** |
|---|---|---|---|---|---|---|---|---|
| Project 11 Recond/Rebuild 510 main line (excl poles) | **Unit Qty.** | **Unit Meas.** | **Hours per Unit** | **Total Hours** | **Total Cost** | **Cost per unit** | **total cost** | **Unit Cost** |
| **Underground Primary Cable Installation** | | | | | | | | |
| 3-Phase 15 kV Cable (1100 Al w/1/6 Con. Neutral) | 880 | CKT FT | 0.040 | 35.2 | $ 2,510.82 | $ 50.00 | $ 44,000.00 | $ 46,510.82 |
| **Trenching** | | | | | | | | |
| Utility Trench for Single Conduit - Good Soil | 880 | LF | 0.070 | 61.6 | $ 4,393.93 | $ - | $ - | $ 4,393.93 |
| **Conduit Installation** | | | | | | | | |
| New 6" PVC Conduit Installation | 880 | LF | 0.040 | 35.2 | $ 2,510.82 | $ 16.00 | $ 14,080.00 | $ 16,590.82 |
| **Switchgear Installation & Equipment** | | | | | | | | |
| Box Pad Base for - Three Phase Switch PME Switchgear | 2 | EA | 5.000 | 10 | $ 713.30 | $ 1,750.00 | $ 3,500.00 | $ 4,213.30 |
| PME-9 Switchgear (2-600 Amp Sw. & 2-200 Amp Fused) | 2 | EA | 32.000 | 64 | $ 4,565.12 | $ 18,000.00 | $ 36,000.00 | $ 40,565.12 |
| **Overhead** | | | | | | | | |
| 45' CL 2 Pole | 0 | EA | 8.500 | 0 | $ - | $ 1,800.00 | $ - | $ - |
| Guy & Anchor | 3 | EA | 4.250 | 12.75 | $ 909.46 | $ 275.00 | $ 825.00 | $ 1,734.46 |
| Three Phase Primary Tangent Pole Top Assembly | 18 | EA | 5.500 | 99 | $ 7,061.67 | $ 475.00 | $ 8,550.00 | $ 15,611.67 |
| Three Phase Primary Single Deadend Pole Top Assembly | 4 | EA | 6.000 | 24 | $ 1,711.92 | $ 775.00 | $ 3,100.00 | $ 4,811.92 |
| Three Phase Primary Conductor (477 kcmil ACSR) | 5025 | CKT FT | 0.044 | 221.1 | $ 15,771.06 | $ 16.00 | $ 80,400.00 | $ 96,171.06 |
| Three Phase - Primary Riser | 2 | EA | 12.500 | 25 | $ 1,783.25 | $ 1,375.00 | $ 2,750.00 | $ 4,533.25 |
| | | | | | | | **Total** | **$ 235,136.34** |

**Subtotals**

| | | | |
|---|---|---|---|
| Total Hours | 587.85 | Subtotal Material | $ 193,205.00 |
| Avg. Labor Rate | $ 71.33 | Subtotal Labor | $ 41,931.34 |
| Sales Tax Material | 0.00% | Subtotal Tax | $ - |
| | | Subtotal Labor, Material & Tax | $ 235,136.34 |
| Equipment & Trucks | $ 40.00 | Subtotal Equipment & Trucks | $ 23,514.00 |
| Contingency | 15.00% | Subtotal Contingency | $ 38,797.55 |
| Engineering | 8.00% | Subtotal Engineering | $ 18,810.91 |
| | | Total Budgetary Estimate | $ 316,258.80 |

## Project 12:

| Underground & Overhead Costs per 100 ft or 1 unit | Quantity | | Labor Cost | | | Material Cost | | Total |
|---|---|---|---|---|---|---|---|---|
| Project 12 Recond/Rebuild 730 main line | Unit Qty. | Unit Meas. | Hours per Unit | Total Hours | Total Cost | Cost per unit | total cost | Unit Cost |
| **Underground Primary Cable Installation** | | | | | | | | |
| 3-Phase 15 kV Cable (1100 Al w/1/6 Con. Neutral) | 4,800 | CKT FT | 0.040 | 192 | $ 13,695.36 | $ 50.00 | $ 240,000.00 | $ 253,695.36 |
| **Trenching** | | | | | | | | |
| Utility Trench for Single Conduit - Good Soil | 4,800 | LF | 0.070 | 336 | $ 23,966.88 | $ - | $ - | $ 23,966.88 |
| **Conduit Installation** | | | | | | | | |
| New 6" PVC Conduit Installation | 4,800 | LF | 0.040 | 192 | $ 13,695.36 | $ 16.00 | $ 76,800.00 | $ 90,495.36 |
| **Switchgear Installation & Equipment** | | | | | | | | |
| Box Pad Base for - Three Phase Switch PME Switchgear | 2 | EA | 5.000 | 10 | $ 713.30 | $ 1,750.00 | $ 3,500.00 | $ 4,213.30 |
| PME-9 Switchgear (2-600 Amp Sw. & 2-200 Amp Fused) | 2 | EA | 32.000 | 64 | $ 4,565.12 | $ 18,000.00 | $ 36,000.00 | $ 40,565.12 |
| **Overhead** | | | | | | | | |
| 45' CL 2 Pole | 0 | EA | 8.500 | 0 | $ - | $ 1,800.00 | $ - | $ - |
| Guy & Anchor | 0 | EA | 4.250 | 0 | $ - | $ 275.00 | $ - | $ - |
| Three Phase Primary Tangent Pole Top Assembly | 0 | EA | 5.500 | 0 | $ - | $ 475.00 | $ - | $ - |
| Three Phase Primary Single Deadend Pole Top Assembly | 0 | EA | 6.000 | 0 | $ - | $ 775.00 | $ - | $ - |
| Three Phase Primary Conductor (477 kcmil ACSR) | 0 | CKT FT | 0.044 | 0 | $ - | $ 16.00 | $ - | $ - |
| Three Phase - Primary Riser | 0 | EA | 12.500 | 0 | $ - | $ 1,375.00 | $ - | $ - |
| | | | | | | | **Total** | **$ 412,936.02** |
| **Subtotals** | | | | | | | | |
| | | | Total Hours | 794 | | Subtotal Material | $ 356,300.00 | |
| Avg. Labor Rate | $ 71.33 | | Subtotal Labor | | $ 56,636.02 | | | |
| Sales Tax Material | 0.00% | | | | | Subtotal Tax | $ - | |
| | | | | | | Subtotal Labor, Material & Tax | | $ 412,936.02 |
| Equipment & Trucks | $ 40.00 | | | | | Subtotal Equipment & Trucks | | $ 31,760.00 |
| Contingency | 15.00% | | | | | Subtotal Contingency | | $ 66,704.40 |
| Engineering | 8.00% | | | | | Subtotal Engineering | | $ 33,034.88 |
| | | | | | | Total Budgetary Estimate | | $ 544,435.30 |

## Project 13:

| Underground & Overhead Costs per 100 ft or 1 unit | Quantity | | Labor Cost | | | Material Cost | | Total |
|---|---|---|---|---|---|---|---|---|
| Project 13 Strong tie Arrowhead Feeder 920 to 330 | Unit Qty. | Unit Meas. | Hours per Unit | Total Hours | Total Cost | Cost per unit | total cost | Unit Cost |
| **Underground Primary Cable Installation** | | | | | | | | |
| 3-Phase 15 kV Cable (1100 Al w/1/6 Con. Neutral) | 1,750 | CKT FT | 0.040 | 70 | $ 4,993.10 | $ 50.00 | $ 87,500.00 | $ 92,493.10 |
| **Trenching** | | | | | | | | |
| Utility Trench for Single Conduit - Good Soil | 1,750 | LF | 0.070 | 122.5 | $ 8,737.93 | $ - | $ - | $ 8,737.93 |
| **Conduit Installation** | | | | | | | | |
| New 6" PVC Conduit Installation | 1,750 | LF | 0.040 | 70 | $ 4,993.10 | $ 16.00 | $ 28,000.00 | $ 32,993.10 |
| **Switchgear Installation & Equipment** | | | | | | | | |
| Box Pad Base for - Three Phase Switch PME Switchgear | 1 | EA | 5.000 | 5 | $ 356.65 | $ 1,750.00 | $ 1,750.00 | $ 2,106.65 |
| PME-9 Switchgear (2-600 Amp Sw. & 2-200 Amp Fused) | 1 | EA | 32.000 | 32 | $ 2,282.56 | $ 18,000.00 | $ 18,000.00 | $ 20,282.56 |
| **Overhead** | | | | | | | | |
| 45' CL 2 Pole | 16 | EA | 8.500 | 136 | $ 9,700.88 | $ 1,800.00 | $ 28,800.00 | $ 38,500.88 |
| Guy & Anchor | 5 | EA | 4.250 | 21.25 | $ 1,515.76 | $ 275.00 | $ 1,375.00 | $ 2,890.76 |
| Three Phase Primary Tangent Pole Top Assembly | 15 | EA | 5.500 | 82.5 | $ 5,884.73 | $ 475.00 | $ 7,125.00 | $ 13,009.73 |
| Three Phase Primary Single Deadend Pole Top Assembly | 2 | EA | 6.000 | 12 | $ 855.96 | $ 775.00 | $ 1,550.00 | $ 2,405.96 |
| Three Phase Primary Conductor (477 kcmil ACSR) | 3650 | CKT FT | 0.044 | 160.6 | $ 11,455.60 | $ 16.00 | $ 58,400.00 | $ 69,855.60 |
| Three Phase - Primary Riser | 8 | EA | 12.500 | 100 | $ 7,133.00 | $ 1,375.00 | $ 11,000.00 | $ 18,133.00 |
| | | | | | | | **Total** | **$ 301,409.26** |

**Subtotals**

| | | | |
|---|---|---|---|
| | | Total Hours | 811.85 |
| | | Subtotal Material | $ 243,500.00 |
| Avg. Labor Rate | $ 71.33 | Subtotal Labor | $ 57,909.26 |
| Sales Tax Material | 0.00% | Subtotal Tax | $ - |
| | | Subtotal Labor, Material & Tax | $ 301,409.26 |
| Equipment & Trucks | $ 40.00 | Subtotal Equipment & Trucks | $ 32,474.00 |
| Contingency | 15.00% | Subtotal Contingency | $ 50,082.49 |
| Engineering | 8.00% | Subtotal Engineering | $ 24,112.74 |
| | | Total Budgetary Estimate | $ 408,078.49 |

## Project 14:

| Project 14 Southwest Substation | Quantity | | Labor Cost | | | Material Cost | | Total |
|---|---|---|---|---|---|---|---|---|
| | Unit Qty. | Unit Meas. | Hours per Unit | Total Hours | Total Cost | Cost per unit | total cost | Unit Cost |
| **Substation Equipment and Installation** | | | | | | | | |
| 46 kV -12.47 kV 12/20 MVA Tansformer | 1 | EA | 100.000 | 100 | $ 7,133.00 | $ 1,500,000.00 | $ 1,500,000.00 | $ 1,507,133.00 |
| 46 kV High Side Breaker | 1 | EA | 20.000 | 20 | $ 1,426.60 | $ 67,600.00 | $ 67,600.00 | $ 69,026.60 |
| 46 kV GOAB Switch | 1 | EA | 24.000 | 24 | $ 1,711.92 | $ 14,560.00 | $ 14,560.00 | $ 16,271.92 |
| 46 kV Relaying VT | 3 | EA | 6.000 | 18 | $ 1,283.94 | $ 9,880.00 | $ 29,640.00 | $ 30,923.94 |
| 15 kV GOAB Switch | 1 | EA | 16.000 | 16 | $ 1,141.28 | $ 5,620.00 | $ 5,620.00 | $ 6,761.28 |
| 15 kV Recloser | 4 | EA | 16.000 | 64 | $ 4,565.12 | $ 8,530.00 | $ 34,120.00 | $ 38,685.12 |
| 15 kV VT | 4 | EA | 4.000 | 16 | $ 1,141.28 | $ 2,080.00 | $ 8,320.00 | $ 9,461.28 |
| 15 kV 1 phase fused disconnect | 16 | EA | 2.000 | 32 | $ 2,282.56 | $ 5,720.00 | $ 91,520.00 | $ 93,802.56 |
| 15 kV 1 phase Hookstick Switch | 24 | EA | 2.000 | 48 | $ 3,423.84 | $ 1,250.00 | $ 30,000.00 | $ 33,423.84 |
| Metering/Relaying | 1 | EA | 120.000 | 120 | $ 8,559.60 | $ 95,000.00 | $ 95,000.00 | $ 103,559.60 |
| Steel Structures | 1 | EA | 266.000 | 266 | $ 18,973.78 | $ 370,000.00 | $ 370,000.00 | $ 388,973.78 |
| Concrete Foundations | 1 | EA | 212.000 | 212 | $ 15,121.96 | $ 429,700.00 | $ 429,700.00 | $ 444,821.96 |
| Substation Bus & Material | 1 | EA | 596.000 | 596 | $ 42,512.68 | $ 227,000.00 | $ 227,000.00 | $ 269,512.68 |
| Substation Conduit & Cable | 1 | EA | 487.000 | 487 | $ 34,737.71 | $ 119,100.00 | $ 119,100.00 | $ 153,837.71 |
| Substation Grounding | 1 | EA | 160.000 | 160 | $ 11,412.80 | $ 26,000.00 | $ 26,000.00 | $ 37,412.80 |
| Substation Site Work | 500 | CUYD | 0.100 | 50 | $ 3,566.50 | $ 60.00 | $ 30,000.00 | $ 33,566.50 |
| Substation SCADA & Communications | 1 | EA | 48.000 | 48 | $ 3,423.84 | $ 15,600.00 | $ 15,600.00 | $ 19,023.84 |
| 15 kV Distribution Feeders | 4 | EA | 180.000 | 720 | $ 51,357.60 | $ 166,950.00 | $ 667,800.00 | $ 719,157.60 |
| Substation Testing & Commissioning | 1 | EA | 375.000 | 375 | $ 26,748.75 | $ 3,900.00 | $ 3,900.00 | $ 30,648.75 |
| **Underground Primary Cable Installation** | | | | | | | | |
| 3-Phase 15 kV Cable (1100 Al w/1/6 Con. Neutral) | 3,400 | CKT FT | 0.040 | 136 | $ 9,700.88 | $ 50.00 | $ 170,000.00 | $ 179,700.88 |
| **Trenching** | | | | | | | | |
| Utility Trench for Single Conduit - Good Soil | 3,000 | LF | 0.070 | 210 | $ 14,979.30 | $ - | $ - | $ 14,979.30 |
| **Conduit Installation** | | | | | | | | |
| New 6" PVC Conduit Installation | 3,000 | LF | 0.040 | 120 | $ 8,559.60 | $ 16.00 | $ 48,000.00 | $ 56,559.60 |
| **Switchgear Installation & Equipment** | | | | | | | | |
| Box Pad Base for - Three Phase Switch PME Switchgear | 4 | EA | 5.000 | 20 | $ 1,426.60 | $ 1,750.00 | $ 7,000.00 | $ 8,426.60 |
| PME-9 Switchgear (2-600 Amp Sw. & 2-200 Amp Fused) | 4 | EA | 32.000 | 128 | $ 9,130.24 | $ 18,000.00 | $ 72,000.00 | $ 81,130.24 |
| **Overhead** | | | | | | | | |
| 45' CL 2 Pole | 4 | EA | 8.500 | 34 | $ 2,425.22 | $ 1,800.00 | $ 7,200.00 | $ 9,625.22 |
| Guy & Anchor | 4 | EA | 4.250 | 17 | $ 1,212.61 | $ 275.00 | $ 1,100.00 | $ 2,312.61 |
| Three Phase Primary Tangent Pole Top Assembly | 0 | EA | 5.500 | 0 | $ - | $ 475.00 | $ - | $ - |
| Three Phase Primary Single Deadend Pole Top Assembly | 4 | EA | 6.000 | 24 | $ 1,711.92 | $ 775.00 | $ 3,100.00 | $ 4,811.92 |
| Three Phase Primary Conductor (477 kcmil ACSR) | 0 | CKT FT | 0.044 | 0 | $ - | $ 16.00 | $ - | $ - |
| Three Phase - Primary Riser | 4 | EA | 12.500 | 50 | $ 3,566.50 | $ 1,375.00 | $ 5,500.00 | $ 9,066.50 |
| | | | | | | | **Total** | **$ 4,372,617.63** |

**Subtotals**

| | | | |
|---|---|---|---|
| | | Total Hours | 4111 |
| | | Subtotal Material | $ 4,079,380.00 |
| Avg. Labor Rate | $ 71.33 | Subtotal Labor | $ 293,237.63 |
| Sales Tax Material | 0.00% | Subtotal Tax | $ - |
| | | Subtotal Labor, Material & Tax | $ 4,372,617.63 |
| Equipment & Trucks | $ 40.00 | Subtotal Equipment & Trucks | $ 164,440.00 |
| Contingency | 15.00% | Subtotal Contingency | $ 680,558.64 |
| Engineering | 8.00% | Subtotal Engineering | $ 349,809.41 |
| | | Total Budgetary Estimate | $ 5,567,425.68 |
| | | Plus T-Line | $ 682,746.36 |
| | | | $ 6,250,172.05 |

## Project 15:

| Project 15 New North Area Substation | Quantity | | Labor Cost | | | Material Cost | | Total |
|---|---|---|---|---|---|---|---|---|
| | Unit Qty. | Unit Meas. | Hours per Unit | Total Hours | Total Cost | Cost per unit | total cost | Unit Cost |
| **Substation Equipment and Installation** | | | | | | | | |
| 46 kV -12.47 kV 12/20 MVA Tansformer | 1 | EA | 100.000 | 100 | $ 7,133.00 | $ 1,500,000.00 | $ 1,500,000.00 | $ 1,507,133.00 |
| 46 kV High Side Breaker | 1 | EA | 20.000 | 20 | $ 1,426.60 | $ 67,600.00 | $ 67,600.00 | $ 69,026.60 |
| 46 kV GOAB Switch | 1 | EA | 24.000 | 24 | $ 1,711.92 | $ 14,560.00 | $ 14,560.00 | $ 16,271.92 |
| 46 kV Relaying VT | 3 | EA | 6.000 | 18 | $ 1,283.94 | $ 9,880.00 | $ 29,640.00 | $ 30,923.94 |
| 15 kV GOAB Switch | 1 | EA | 16.000 | 16 | $ 1,141.28 | $ 5,620.00 | $ 5,620.00 | $ 6,761.28 |
| 15 kV Recloser | 4 | EA | 16.000 | 64 | $ 4,565.12 | $ 8,530.00 | $ 34,120.00 | $ 38,685.12 |
| 15 kV VT | 4 | EA | 4.000 | 16 | $ 1,141.28 | $ 2,080.00 | $ 8,320.00 | $ 9,461.28 |
| 15 kV 1 phase fused disconnect | 16 | EA | 2.000 | 32 | $ 2,282.56 | $ 5,720.00 | $ 91,520.00 | $ 93,802.56 |
| 15 kV 1 phase Hookstick Switch | 24 | EA | 2.000 | 48 | $ 3,423.84 | $ 1,250.00 | $ 30,000.00 | $ 33,423.84 |
| Metering/Relaying | 1 | EA | 120.000 | 120 | $ 8,559.60 | $ 95,000.00 | $ 95,000.00 | $ 103,559.60 |
| Steel Structures | 1 | EA | 266.000 | 266 | $ 18,973.78 | $ 370,000.00 | $ 370,000.00 | $ 388,973.78 |
| Concrete Foundations | 1 | EA | 212.000 | 212 | $ 15,121.96 | $ 429,700.00 | $ 429,700.00 | $ 444,821.96 |
| Substation Bus & Material | 1 | EA | 596.000 | 596 | $ 42,512.68 | $ 227,000.00 | $ 227,000.00 | $ 269,512.68 |
| Substation Conduit & Cable | 1 | EA | 487.000 | 487 | $ 34,737.71 | $ 119,100.00 | $ 119,100.00 | $ 153,837.71 |
| Substation Grounding | 1 | EA | 160.000 | 160 | $ 11,412.80 | $ 26,000.00 | $ 26,000.00 | $ 37,412.80 |
| Substation Site Work | 500 | CUYD | 0.100 | 50 | $ 3,566.50 | $ 60.00 | $ 30,000.00 | $ 33,566.50 |
| Substation SCADA & Communications | 1 | EA | 48.000 | 48 | $ 3,423.84 | $ 15,600.00 | $ 15,600.00 | $ 19,023.84 |
| 15 kV Distribution Feeders | 4 | EA | 180.000 | 720 | $ 51,357.60 | $ 166,950.00 | $ 667,800.00 | $ 719,157.60 |
| Substation Testing & Commissioning | 1 | EA | 375.000 | 375 | $ 26,748.75 | $ 3,900.00 | $ 3,900.00 | $ 30,648.75 |
| **Underground Primary Cable Installation** | | | | | | | | |
| 3-Phase 15 kV Cable (1100 Al w/1/6 Con. Neutral) | 3,400 | CKT FT | 0.040 | 136 | $ 9,700.88 | $ 50.00 | $ 170,000.00 | $ 179,700.88 |
| **Trenching** | | | | | | | | |
| Utility Trench for Single Conduit - Good Soil | 3,000 | LF | 0.070 | 210 | $ 14,979.30 | $ - | $ - | $ 14,979.30 |
| **Conduit Installation** | | | | | | | | |
| New 6" PVC Conduit Installation | 3,000 | LF | 0.040 | 120 | $ 8,559.60 | $ 16.00 | $ 48,000.00 | $ 56,559.60 |
| **Switchgear Installation & Equipment** | | | | | | | | |
| Box Pad Base for - Three Phase Switch PME Switchgear | 4 | EA | 5.000 | 20 | $ 1,426.60 | $ 1,750.00 | $ 7,000.00 | $ 8,426.60 |
| PME-9 Switchgear (2-600 Amp Sw. & 2-200 Amp Fused) | 4 | EA | 32.000 | 128 | $ 9,130.24 | $ 18,000.00 | $ 72,000.00 | $ 81,130.24 |
| **Overhead** | | | | | | | | |
| 45' CL 2 Pole | 4 | EA | 8.500 | 34 | $ 2,425.22 | $ 1,800.00 | $ 7,200.00 | $ 9,625.22 |
| Guy & Anchor | 4 | EA | 4.250 | 17 | $ 1,212.61 | $ 275.00 | $ 1,100.00 | $ 2,312.61 |
| Three Phase Primary Tangent Pole Top Assembly | 0 | EA | 5.500 | 0 | $ - | $ 475.00 | $ - | $ - |
| Three Phase Primary Single Deadend Pole Top Assembly | 4 | EA | 6.000 | 24 | $ 1,711.92 | $ 775.00 | $ 3,100.00 | $ 4,811.92 |
| Three Phase Primary Conductor (477 kcmil ACSR) | 0 | CKT FT | 0.044 | 0 | $ - | $ 16.00 | $ - | $ - |
| Three Phase - Primary Riser | 4 | EA | 12.500 | 50 | $ 3,566.50 | $ 1,375.00 | $ 5,500.00 | $ 9,066.50 |
| | | | | | | | **Total** | **$ 4,372,617.63** |

**Subtotals**

| | | | |
|---|---|---|---|
| Total Hours | 4111 | Subtotal Material | $ 4,079,380.00 |
| Avg. Labor Rate | $ 71.33 | Subtotal Labor | $ 293,237.63 |
| Sales Tax Material | 0.00% | Subtotal Tax | $ - |
| | | Subtotal Labor, Material & Tax | $ 4,372,617.63 |
| Equipment & Trucks | $ 40.00 | Subtotal Equipment & Trucks | $ 164,440.00 |
| Contingency | 15.00% | Subtotal Contingency | $ 680,558.64 |
| Engineering | 8.00% | Subtotal Engineering | $ 349,809.41 |
| | | Total Budgetary Estimate | $ 5,567,425.68 |
| | | Plus T-Line | $ 682,746.36 |
| | | | $ 6,250,172.05 |

Project Payson-2

| | | | | | | |
|---|---|---|---|---|---|---|
| SCADA | | 120000 | (20k each of 5 subs, 20k engineering) | | | |
| OMS | | 100000 | | | | |
| Model | | 190000 | (30k software, 150k field audit, 10k eng) | | | |
| | | | | | | |
| Dispatch | | 23000 | | | | |
| | | | | | | |
| | | | | | | |
| | total | 433000 | | | | |

# 11. APPENDIX E: SUVPS PROJECTS FROM "SOUTHERN UTAH VALLEY JOINT STUDY REPORT, 2022"

Executive Summary and Project Summary Table included here.

## 1.0 EXECUTIVE SUMMARY

The 2022 Southern Utah Valley joint study was initiated to address significant system load growth projections for the area in one study that combines and coordinates the individual study efforts that have previously been performed by SUVPS, SUVPS members, UAMPS and PacifiCorp on their individual transmission systems.

This planning study is the product of representatives of the signatory organizations. The study establishes best system improvement recommendations to serve projected loads based on a single utility concept. The study does not establish the requirement for any party to fund projects or operational considerations. Further discussions regarding cost-sharing and the responsibilities of each party are ongoing and will continue on a project-by-project basis.

The local transmission system in the Southern Utah Valley area was analyzed with projected load from 2022 through 2036. Load projections from each utility were organized by year and imported into 15 corresponding load flow models. Each year has an associated "gross load" derived from the load flow cases, equal to the total load at SUVPS points of interconnection plus the total generation inside the SUVPS system. The gross load does not include other load in the Southern Utah Valley area. More information on load projections can be found in Section 5.

This study recommends projects that are to be constructed at or before a projected gross load level and associated year. Because that load estimation is representative of the system as a whole it is most accurate as a projection for larger system-wide projects, but the projected years and gross load levels may be earlier or later based on actual growth patterns. For this reason, the need for the recommended project should be reassessed by analyzing the conditions of the system with time to complete project procurement and construction. Timely execution of this analysis is necessary to enable completion of the project at or before its associated issue arises.

In addition, the project recommendations and estimated timing assume that every load will grow evenly. However, projects that address thermal and voltage issues occurring on local 46 kV transmission equipment will be more affected by variations in load growth between individual cities. The timing of these projects should therefore be reevaluated by the owners in each area if growth in that area deviates from projections. Further explanation of the issues that drive the need for each project can be found in the descriptions in Section 7.

Study recommendations to meet the projected conditions to 2036 are found in Table 1, organized by ascending load level where the driving issue is first observed:

| Section | Project | Gross Load | Projected Year |
|---|---|---|---|
| 7.1.1 | Mercer-Spanish Fork 345 kV Line | 215 MW | N/A |
| 7.1.2 | New SUVPS Point-of-Interconnection Substation at Spanish Fork (PacifiCorp) | 215 MW | N/A |
| 7.3.1 | Build a new SUVPS POI-Taylor 138 kV Line | 215 MW | 2022 |
| 7.3.2 | Build a new 138-46 kV source at Taylor | 215 MW | 2022 |
| 7.3.3 | Build a new Nebo Power Station-Suter 46 kV Line | 215 MW | 2022 |
| 7.3.4 | Install 46 kV Capacitor Bank at Canyon Road | 215 MW | 2022 |

| Section | Project | Gross Load | Projected Year |
|---|---|---|---|
| 7.2.1 | New Distribution Capacity – 1900S, West (Salem), Leland, New Springville | 243 MW | 2023 |
| 7.3.5 | Install 46 kV Capacitor Bank at Dry Creek | 243 MW | 2023 |
| 7.3.6 | Reconductor Canyon Road-Taylor 46 kV Line | 243 MW | 2023 |
| 7.3.7 | Reconductor Baxter-Dry Creek 46 kV Line | 243 MW | 2023 |
| 7.2.3 | New Distribution Capacity – West (SESD), North (Spanish Fork), North West (Spanish Fork), Oberg (Spanish Fork) | 270 MW | 2024 |
| 7.2.2 | Convert North Substation to 138 kV | 270 MW | 2024 |
| 7.2.4 | New Distribution Capacity – Spanish Fork (PacifiCorp) | 303 MW | 2025 |
| 7.2.5 | New Distribution Capacity – 1700 W (Payson), Veridian (Salem), Hamilton (SESD) | 303 MW | 2025 |
| 7.1.3 | Loop Spanish Fork-Hale 138 kV Line into Dry Creek | 303 MW | 2025 |
| 7.2.6 | New Distribution Capacity – Davis (Salem) | 322 MW | 2026 |
| 7.3.8 | Install Third 138-46 kV Transformer at Dry Creek (Or Upgrade Existing Two) | 322 MW | 2026 |
| 7.3.9 | Install 46 kV Capacitor Bank at Suter | 322 MW | 2026 |
| 7.3.10 | Reconductor Strawberry-SUVPS POI 46 kV Line | 337 MW | 2027 |
| 7.3.11 | Install 46 kV Capacitor Bank at Taylor | 353 MW | 2028 |
| 7.3.12 | Reconductor Strawberry-Hamilton-Veridian 46 kV Line | 353 MW | 2028 |
| 7.3.13 | Reconductor Dry Creek-New Springville 46 kV Line | 385 MW | 2030 |
| 7.3.14 | Build new Nebo Power Station-Taylor 138 kV Line | 403 MW | 2031 |
| 7.3.15 | Reconductor Payson 46 kV Lines | 420 MW | 2032 |
| 7.3.16 | Reconductor Veridian-Davis Tap 46 kV Line | 437 MW | 2033 |
| 7.1.4 | Create a Transfer-Trip Scheme for Dry Creek-Spanish Fork Outages | 437 MW | 2033 |
| 7.1.5 | Reconductor Clover Tap-Nebo (PacifiCorp) 138 kV Line | 455 MW | 2034 |
| 7.3.17 | Move Normal-Open Point from Whitehead to Woodhouse | 472 MW | 2035 |

**Table 1 – Summary of Projects**

Note: Estimated years for "Distribution Capacity" projects were furnished by each utility and not determined by this study.

PAYSON
UTAH
HOME TO ADVENTURE

# Payson Power

## Electric Impact Fee Analysis

**April 2024**

UFS UTILITY FINANCIAL SOLUTIONS, LLC

Corporate location:
Utility Financial Solutions, LLC
185 Sun Meadow Court
Holland, MI USA 49424
(616) 393-9722
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Submitted Respectfully by:
Mark Beauchamp, CPA, CMA, MBA
President, Utility Financial Solutions, LLC
mbeauchamp@ufsweb.com
(616) 393-9722

April 2024

David Tuckett
City Manager
Payson Power
439 W. Utah Ave.
Payson, UT 84651

Dear Mr. Tuckett:

We are pleased to present a final report for the Impact Fee Analysis for Payson Power (Payson). This report was prepared to provide Payson with a comprehensive examination of its existing impact fee structure by an outside party.

The specific purposes of this rate study are:

- Identify the fixed cost contributions to plant a new customer provides through electric rate tariffs
- Identify gross investment in plant necessary to service new growth at various sizes and voltages
- Determine impact fees by subtracting the present value of the fixed cost contributions from the impacts on plant

This report utilizes results of the electric cost of service study, financial projections performed in 2022 and Payson's capital improvement plan.

This report is intended for information and use by the utility and management for the purposes stated above and is not intended to be used by anyone except the specified parties.

Sincerely,

Utility Financial Solutions, LLC
Mark Beauchamp, President
185 Sun Meadow Ct
Holland, MI 49424

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## LIST OF TABLES

## Introduction

This report identifies the impact fees Payson Power should charge to new customers by identifying the amount new customers contribute to system expansion through rates and subtracting the costs for expansion of the system. The purpose of this analysis is to help ensure:

- New customers are not subsidizing existing customers.
- Existing customers are not subsidizing new customers.

This analysis helps to ensure that all customers benefit from growth without being negatively affected by rate increases resulting from system expansion. Growth necessitates additional capacity investments, which often occur intermittently, and cash generated from impact fees is utilized to fund these expansions.

As new customers are integrated into the system, Payson acquires contribution margins from rates to partially cover the fixed infrastructure costs. When the governing body establishes electric rates, they incorporate a recovery component for the replacement cost of existing assets, which new customers contribute to through the rates they are charged. This is commonly referred to as net revenue, which can be allocated to offset a portion of the system expansions.

However, when the costs of system expansion exceed the net revenues generated from customers, it leads to the necessity of impact charges for new customers, as detailed in this report.

## Steps to Complete the Analysis

The following steps were taken to complete the impact fee analysis:

1) Identify the contribution margins (Net Revenues) generated by rate tariffs and used to fund replacement cost of existing infrastructure.
2) The contribution margins are valued over an appropriate period to determine the present value of the new customer's contribution.
3) Evaluate and categorize plant investments into two groups: those designated for future growth and other investments intended for either infrastructure replacement or projects that do not enhance the capacity of the system.
4) Divide the total system cost impacts of new plant investments by residential equivalent factors. This value is then reduced by the value of the contribution margins generated from rates.
5) The residential equivalent factors are converted to amperage and ratioed to each amperage based on the potential capacity needs of each customer.

## Step One – Determination of Contribution Margin

Contribution margins were calculated for each class by subtracting variable costs typically power supply costs from revenues to identify the contribution margins generated by each class.

**Revenue minus variable cost equals contribution margin**

Table 1 identifies the total revenue requirements for each class and subtracts the variable costs to identify the fixed cost recoveries for each class of customers. Expense used in the analysis is from the cost of service study completed in 2023. Variable costs are primarily driven by power supply and transmission costs, and most of the distribution system is classified as fixed cost recovery. This includes distribution and sub-transmission cost recovery used to fund operation, maintenance, replacement, and expansion of the distribution and sub-transmission system. Table 1 below identifies the total recovery of distribution operations for each class.

**Table 1 – Contribution Margin by Class**

| Expense Description | Expense Classification | Residential | Commercial Electric - No Demand | Commercial Electric - Demand | Industrial 1 Electric | Industrial 2 Electric |
|---|---|---|---|---|---|---|
| Power Supply Expenses: | | | | | | |
| Summer Demand | Variable | $ 1,607,970 | $ 40,668 | $ 792,059 | $ 228,561 | $ 115,202 |
| Summer Energy | Variable | 839,730 | 23,362 | 477,023 | 202,439 | 67,607 |
| Winter Demand | Variable | 704,929 | 22,933 | 347,403 | 96,244 | 58,330 |
| Winter Energy | Variable | 1,222,255 | 46,409 | 958,082 | 363,031 | 156,372 |
| Inter 2 Demand | Variable | 310,171 | 14,038 | 251,057 | 57,141 | 36,804 |
| Inter 2 Energy | Variable | 406,805 | 14,237 | 336,114 | 120,812 | 47,222 |
| Inter 4 Demand | Variable | 393,084 | 19,422 | 450,682 | 140,701 | 86,196 |
| Inter 4 Energy | Variable | 641,918 | 26,431 | 603,249 | 245,603 | 105,539 |
| Distribution Expenses: | | | | | | |
| Distribution | Fixed | 602,824 | 18,472 | 356,329 | 102,824 | 53,249 |
| Transmission | Fixed | 338,511 | 10,373 | 200,094 | 57,740 | 29,902 |
| Transformer | Fixed | 102,788 | 3,150 | 60,758 | 17,533 | 9,080 |
| Substation | Fixed | 773,561 | 23,704 | 457,252 | 131,947 | 68,331 |
| Customer Related Expenses: | | | | | | |
| Distribution Customer Costs | Variable | 269,855 | 14,560 | 66,259 | (1,313) | (280) |
| Transformer Customer Costs | Variable | 81,144 | 2,147 | 4,234 | 24 | 24 |
| Substation Customer Costs | Variable | 128,972 | 6,825 | 33,651 | 379 | 379 |
| Meter O&M | Variable | 191,395 | 9,700 | 24,594 | 183 | 183 |
| Meter Reading | Variable | 115,332 | 6,103 | 30,092 | 170 | 170 |
| Billing | Variable | 115,329 | 6,103 | 30,091 | 170 | 170 |
| Services | Fixed | 296,731 | 13,880 | 104,431 | 14,585 | 7,858 |
| Customer Service | Fixed | 253,797 | 13,430 | 66,219 | 746 | 746 |
| Total | | $ 9,397,103 | $ 335,946 | $ 5,649,675 | $ 1,779,520 | $ 843,081 |
| Total Fixed | | $ 1,779,770 | $ 62,052 | $ 789,316 | $ 146,206 | $ 96,866 |

## Step Two - Contribution Margin Unit Conversion

The contribution to margin (Net Revenue) is present valued over a specified time period to determine the maximum value a new customer will generate over an appropriate recovery period. Table 2 shows the average net revenue generated by each customer type on a per kWh or kW basis. For example, each kWh sold to the residential class generated $0.0301 cents of fixed cost recovery used to fund the distribution system.

**Table 2 – Determination of Present Value of Contribution Margins**

| Customer Class | Recovery Period (Years) | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|---|
| Residential | 7 | $ 0.0301 | $ 0.0301 | $ 0.0301 | $ 0.0301 | $ 0.0301 | $ 0.0301 | $ 0.0301 |
| Commercial Electric - No Demand | 5 | 0.0295 | 0.0295 | 0.0295 | 0.0295 | 0.0295 | - | - |
| Commercial Electric - Demand | 5 | 6.13 | 6.13 | 6.13 | 6.13 | 6.13 | - | - |
| Industrial 1 Electric | 5 | 4.26 | 4.26 | 4.26 | 4.26 | 4.26 | - | - |
| Industrial 2 Electric | 5 | 4.76 | 4.76 | 4.76 | 4.76 | 4.76 | - | - |

Table 3 details the value of the contribution margins by customer class. The value of the fixed cost recovery for a typical residential customer is $1,460.

**Table 3 – Average Contribution Margin per Billing Basis**

| Customer Class | COS Revenue Requirement | Fixed Costs Contribution | Average Contribution per Customer | Recovery Period (Years) | Maximum Utility Investment per Customer |
|---|---|---|---|---|---|
| Residential | $ 9,985,546 | $ 1,779,770 | $ 262 | 7 | $ 1,460 |
| Commercial Electric - No Demand | 356,902 | 62,052 | 345 | 5 | 1,452 |
| Commercial Electric - Demand | 6,105,443 | 789,316 | 2,223 | 5 | 9,366 |
| Industrial 1 Electric | 1,958,690 | 146,206 | 73,103 | 5 | 307,936 |
| Industrial 2 Electric | 915,380 | 96,866 | 48,433 | 5 | 204,018 |

## Step Three - Infrastructure Cost Analysis

The determination of impact fees depends on the additional capacity needed to service new load and is expressed by amperage and voltage requirements.

The infrastructure costs are broken down into the following components:

- Distribution Local – Investments made to service customers peak demands
- Distribution Substation – Investments made to service peaks of customers located in specific areas
- System Substations – Investments made to handle Payson's peak demands
- Transmission System – Investments made to handle Payson's peak demands

Payson provided a capacity plan for the total system with a breakout of the amount attributed to expansion due to growth. The table below outlines the projected Payson investments in plant, the additional capacity provided by the investments, the expansion costs on a per kW basis, and the location of the capacity investment.

In addition, Payson provided historic record of impact fee related revenue and expenditures since the 2022 study. To accurately reflect revenue related to outstanding projects, UFS allocated the net fund balance at Year End 2023 to the components below.

Table 4 is used to identify the cost impacts associated with each type of cost component.

**Table 4 – Cost of Additional Investment in Plant**

| Capital Projects | Impact Related % | Start Date | Bonding - Impact only | Bonded | Bonding Years | Bonding Interest | Total to be Spent (net of past spending) | Impact Fee Cost |
|---|---|---|---|---|---|---|---|---|
| New Power Resource | 56% | 2024 | $ 18,513,000 | Yes | 20 | 5.0% | $ 33,000,000 | **$ 18,513,000** |
| SUVPS Bond Payment-Impact Fee | 50% | 2024 - 2033 | 3,840,000 | Yes | 25 | 5.0% | 7,680,000 | **3,840,000** |
| South Substation, T-line, Feeders | 83% | 2024 | 6,970,128 | Yes | 20 | 5.0% | 8,367,500 | **6,970,128** |
| North/Arrowhead Substation, T-line, Feeders | 73% | 2025 | 4,581,470 | Yes | 20 | 5.0% | 6,250,300 | **4,581,470** |
| Strong Tie Feeders 510 - 730 | 53% | 2025 | - | No | | | 205,300 | **107,783** |
| Feeder 510/610 I-15 Crossing | 45% | 2024 | - | No | | | 74,400 | **33,406** |
| South Substation tie to 800 South SR-198/500W | 44% | 2024 | - | No | | | 244,100 | **107,648** |
| Strong Tie Feeders 710 - 320 | 49% | 2024 | - | No | | | 368,500 | **180,197** |
| 46 kV T-loop to South Substation | 29% | 2025 | - | No | | | 2,448,700 | **697,880** |
| South Substation 810 tie to 510/730 | 41% | 2024 | - | No | | | 628,000 | **257,480** |
| Rebuild 330 Mainline | 42% | 2027 | - | No | | | 369,900 | **153,509** |
| Strong Tie Feeders Arrowhead 920 - 330 | 48% | 2029 | - | No | | | 496,600 | **238,368** |
| 510 Mainline | 55% | 2027 | - | No | | | 355,800 | **194,978** |
| 730 Mainline | 28% | 2027 | - | No | | | 612,500 | **170,275** |
| Southwest Substation and Feeders | 30% | 2029 | 2,311,768 | Yes | 20 | 5.0% | 7,604,500 | **2,311,768** |
| North Substation and Feeders | 30% | 2029 | 2,311,768 | Yes | 20 | 5.0% | 7,604,500 | **2,311,768** |
| **Total** | | | | | | | **$ 76,967,200** | **$ 41,029,257** |

## Step Four – Determine Cost Impact per Residential Equivalent Unit

Payson's base installation for a residential home is 100 AMP 120/240 volt service. To determine the impact fee, UFS conducts the following steps.

1. Determine growth in kWh sales due to impact fee related projects
2. Convert growth to a residential equivalent unit (REU) based on average residential monthly use
3. Divide the adjusted impact fee investment by the REU to determine average cost
4. Subtract the maximum utility contribution to determine the impact fees to be recovered per REU

### Table 5 – Calculation of Impact Fees by REU

| Capital Projects | Start Date | Bonding - Impact only | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | Six Year Total |
|---|---|---|---|---|---|---|---|---|---|
| New Power Resource | 2024 | $ 18,513,000 | $ 1,485,531 | $ 1,485,531 | $ 1,485,531 | $ 1,485,531 | $ 1,485,531 | $ 1,485,531 | $ 8,913,186 |
| SUVPS Bond Payment-Impact Fee | 2024 - 2033 | 3,840,000 | 272,457 | 272,457 | 272,457 | 272,457 | 272,457 | 272,457 | 1,634,745 |
| South Substation, T-line, Feeders | 2024 | 6,970,128 | 559,301 | 559,301 | 559,301 | 559,301 | 559,301 | 559,301 | 3,355,806 |
| North/Arrowhead Substation, T-line, Feeders | 2025 | 4,581,470 | 367,629 | 367,629 | 367,629 | 367,629 | 367,629 | 367,629 | 2,205,774 |
| Strong Tie Feeders 510 - 730 | 2025 | - | - | 107,783 | - | - | - | - | 107,783 |
| Feeder 510/610 I-15 Crossing | 2024 | - | 33,406 | - | - | - | - | - | 33,406 |
| South Substation tie to 800 South SR-198/500W | 2024 | - | 107,648 | - | - | - | - | - | 107,648 |
| Strong Tie Feeders 710 - 320 | 2024 | - | 180,197 | - | - | - | - | - | 180,197 |
| 46 kV T-loop to South Substation | 2025 | - | - | 697,880 | - | - | - | - | 697,880 |
| South Substation 810 tie to 510/730 | 2024 | - | 257,480 | - | - | - | - | - | 257,480 |
| Rebuild 330 Mainline | 2027 | - | - | - | - | 153,509 | - | - | 153,509 |
| Strong Tie Feeders Arrowhead 920 - 330 | 2029 | - | - | - | - | - | - | 238,368 | 238,368 |
| 510 Mainline | 2027 | - | - | - | - | 194,978 | - | - | 194,978 |
| 730 Mainline | 2027 | - | - | - | - | 170,275 | - | - | 170,275 |
| Southwest Substation and Feeders | 2029 | 2,311,768 | 185,502 | 185,502 | 185,502 | 185,502 | 185,502 | 185,502 | 1,113,013 |
| North Substation and Feeders | 2029 | 2,311,768 | 185,502 | 185,502 | 185,502 | 185,502 | 185,502 | 185,502 | 1,113,013 |
| **Total** | | | $ 3,634,653 | $ 3,861,585 | $ 3,055,923 | $ 3,574,685 | $ 3,055,923 | $ 3,294,291 | $ 20,477,060 |
| Less Current Impact Fee Balance | | | | | | | | | $ (1,592,226) |
| **Net Impact Fee Recovery** | | | | | | | | | **$ 18,884,834** |

| Determination of Residential Equivalent Units | | Base Impact Fee - 200 Watt |
|---|---|---|
| Actual kWh Purchases 2023 | | 140,719,395 |
| Projected kWh Purchases 2028 | | 168,827,225 |
| Change in Purchases adjusted for losses | | 27,105,388 |
| Average Residential kWh annual use | | 8,692 |
| **Residential Equivalent Units** | | **3,118** |
| Total Investment | $ | 18,884,834 |
| Average cost per Residential Equivalent | $ | 6,056 |
| Less Maximum Utility Contribution | | 1,460 |
| **Impact Fees to be recovered per Residential Equivalent** | **$** | **4,596** |

Therefore, a 200 AMP 120/240 volt service requires $4,596 to be recovered through impact fees.

## Step Five – Conversion to Amperage

Table 6 expresses the Table 5 results by amperage and voltage level using a typical residential customer's 200 AMP service voltage as the base.

**Table 6 – Impact Fees by Amperage and Voltage Level**

| | 120/240 Volt | 120/208 Volt | 277/480 Volt |
|---|---|---|---|
| AMPS | Impact Fee | Impact Fee | Impact Fee |
| 10 | $ 230 | $ 345 | $ 796 |
| 20 | 460 | 690 | 1,592 |
| 30 | 689 | 1,035 | 2,388 |
| 40 | 919 | 1,380 | 3,184 |
| 50 | 1,149 | 1,725 | 3,980 |
| 60 | 1,379 | 2,070 | 4,776 |
| 70 | 1,609 | 2,414 | 5,572 |
| 80 | 1,838 | 2,759 | 6,368 |
| 90 | 2,068 | 3,104 | 7,164 |
| 100 | 2,298 | 3,449 | 7,960 |
| 125 | 2,872 | 4,312 | 9,950 |
| 150 | 3,447 | 5,174 | 11,940 |
| 175 | 4,021 | 6,036 | 13,930 |
| 200 | 4,596 | 6,899 | 15,920 |
| 300 | 6,894 | 10,348 | 23,880 |
| 400 | 9,192 | 13,797 | 31,840 |
| 500 | 11,489 | 17,246 | 39,799 |
| 600 | 13,787 | 20,696 | 47,759 |
| 700 | 16,085 | 24,145 | 55,719 |
| 800 | 18,383 | 27,594 | 63,679 |
| 900 | 20,681 | 31,044 | 71,639 |
| 1000 | 22,979 | 34,493 | 79,599 |
| 1100 | 25,277 | 37,942 | 87,559 |
| 1200 | 27,575 | 41,391 | 95,519 |
| 1300 | 29,873 | 44,841 | 103,478 |
| 1400 | 32,170 | 48,290 | 111,438 |
| 1500 | 34,468 | 51,739 | 119,398 |
| 1600 | 36,766 | 55,189 | 127,358 |
| 1700 | 39,064 | 58,638 | 135,318 |
| 1800 | 41,362 | 62,087 | 143,278 |
| 1900 | 43,660 | 65,536 | 151,238 |
| 2000 | 45,958 | 68,986 | 159,198 |
| 2500 | 57,447 | 86,232 | 198,997 |
| 3000 | 68,937 | 103,478 | 238,796 |

## Significant Assumptions

The following assumptions are made in the creation of this report:

1) **Discount Rate** – 6.0%
2) **Recovery Period:**
   All Residential Services – 7 year recovery
   Commercial and Industrial – 5 year recovery

## Statistical Information

**Table 7 – Class Load Data and Statistics**

Statistics are from the base year for the cost of service study for July 2021 – June 2022.

| Description | Residential | Commercial Electric - No Demand | Commercial Electric - Demand | Industrial 1 Electric | Industrial 2 Electric |
|---|---|---|---|---|---|
| Number of Customers | 6,803 | 180 | 355 | 2 | 2 |
| Energy at Meter | 59,134,908 | 2,105,957 | 45,801,857 | 18,005,509 | 7,265,562 |
| NCP Meter | 17,863 | 560 | 10,559 | 3,047 | 1,639 |
| NCP Primary | 18,709 | 581 | 11,059 | 3,191 | 1,688 |
| NCP Input | 19,586 | 600 | 11,577 | 3,341 | 1,730 |
| Average Load Factor | 19% | 16% | 16% | 24% | 16% |
| Group Diversity Factor | 100% | 100% | 85% | 85% | 91% |
| Monthly Distribution Max NCP | 36,003 | 1,510 | 32,212 | 8,520 | 5,138 |

## Considerations

Currently, some new customers are not contributing enough to cover the cost of capacity upgrades to the system, while others are over contributing. The tables below compare the current and proposed impact fees. However, UFS proposes to charge impact fees based on the voltage and amperage of service outlined in Table 6.

### Table 8 – 120/240 Voltage Current vs. Proposed Fees

| Residential Single Phase (120/240V) | | | | | | |
|---|---|---|---|---|---|---|
| Amps | kVA | Max Capacity (kW) | Average Use (kW) | Current Fee | Proposed Fee | % Change |
| 60 | 14.4 | 2.00 | 1.20 | $ 739 | $ 1,379 | 87% |
| 100 | 24 | 5.00 | 2.00 | $ 1,263 | $ 2,298 | 82% |
| 125 | 30 | 6.00 | 2.40 | $ 1,515 | $ 2,872 | 90% |
| 150 | 36 | 7.00 | 2.80 | $ 1,768 | $ 3,447 | 95% |
| 200 | 48 | 8.00 | 3.20 | $ 2,021 | $ 4,596 | 127% |
| 225 | 54 | 10.00 | 4.00 | $ 2,526 | $ 3,550 | 41% |
| 400 | 96 | 14.00 | 5.60 | $ 3,536 | $ 9,192 | 160% |
| **Commercial (120/240V)** | | | | | | |
| Amps | kVA | Max Capacity | Average Use | Current | Proposed | % Change |
| 100 | 24 | 5.00 | 2.25 | $ 1,421 | $ 2,298 | 62% |
| 125 | 30 | 7.00 | 3.15 | $ 1,989 | $ 2,872 | 44% |
| 150 | 36 | 9.00 | 4.05 | $ 2,557 | $ 3,447 | 35% |
| 200 | 48 | 14.00 | 6.30 | $ 3,978 | $ 4,596 | 16% |
| 400 | 96 | 19.00 | 8.55 | $ 5,399 | $ 9,192 | 70% |

### Table 9 – 120/208 Voltage Current vs. Proposed Fees

| Commercial 3 Phase (120/208V) | | | | | | |
|---|---|---|---|---|---|---|
| Amps | kVA | Max Capacity | Average Use | Current | Proposed | % Change |
| 125 | 45 | 16.00 | 7.00 | $ 4,546 | $ 4,312 | -5% |
| 150 | 54 | 24.00 | 11.00 | $ 6,819 | $ 5,174 | -24% |
| 200 | 72 | 31.00 | 14.00 | $ 8,808 | $ 6,899 | -22% |
| 400 | 144 | 63.00 | 28.00 | $ 17,900 | $ 13,797 | -23% |
| 600 | 216 | 94.00 | 42.00 | $ 26,709 | $ 20,696 | -23% |
| 800 | 288 | 126.00 | 57.00 | $ 35,801 | $ 27,594 | -23% |
| 1,000 | 360 | 157.00 | 71.00 | $ 44,609 | $ 34,493 | -23% |
| 1,200 | 432 | 189.00 | 85.00 | $ 53,701 | $ 41,391 | -23% |
| 1,600 | 576 | 252.00 | 113.00 | $ 71,602 | $ 55,189 | -23% |
| 2,000 | 720 | 315.00 | 142.00 | $ 89,502 | $ 68,986 | -23% |

### Table 10 – 277/480 Voltage Current vs. Proposed Fees

| Commercial 3 Phase (277/480V) | | | | | | |
|---|---|---|---|---|---|---|
| Amps | kVA | Max Capacity | Average Use | Current | Proposed | % Change |
| 125 | 104 | 35 | 16 | $ 9,945 | $ 9,950 | 0% |
| 150 | 125 | 52 | 23 | $ 14,775 | $ 11,940 | -19% |
| 200 | 166 | 73 | 33 | $ 20,742 | $ 15,920 | -23% |
| 400 | 332 | 145 | 65 | $ 41,199 | $ 31,840 | -23% |

## Proposed Rate Design

**Table 11 – Proposed Impact Fees by Amperage and Voltage**

| | 120/240 Volt | 120/208 Volt | 277/480 Volt |
|---|---|---|---|
| AMPS | Impact Fee | Impact Fee | Impact Fee |
| 10 | $ 230 | $ 345 | $ 796 |
| 20 | 460 | 690 | 1,592 |
| 30 | 689 | 1,035 | 2,388 |
| 40 | 919 | 1,380 | 3,184 |
| 50 | 1,149 | 1,725 | 3,980 |
| 60 | 1,379 | 2,070 | 4,776 |
| 70 | 1,609 | 2,414 | 5,572 |
| 80 | 1,838 | 2,759 | 6,368 |
| 90 | 2,068 | 3,104 | 7,164 |
| 100 | 2,298 | 3,449 | 7,960 |
| 125 | 2,872 | 4,312 | 9,950 |
| 150 | 3,447 | 5,174 | 11,940 |
| 175 | 4,021 | 6,036 | 13,930 |
| 200 | 4,596 | 6,899 | 15,920 |
| 300 | 6,894 | 10,348 | 23,880 |
| 400 | 9,192 | 13,797 | 31,840 |
| 500 | 11,489 | 17,246 | 39,799 |
| 600 | 13,787 | 20,696 | 47,759 |
| 700 | 16,085 | 24,145 | 55,719 |
| 800 | 18,383 | 27,594 | 63,679 |
| 900 | 20,681 | 31,044 | 71,639 |
| 1000 | 22,979 | 34,493 | 79,599 |
| 1100 | 25,277 | 37,942 | 87,559 |
| 1200 | 27,575 | 41,391 | 95,519 |
| 1300 | 29,873 | 44,841 | 103,478 |
| 1400 | 32,170 | 48,290 | 111,438 |
| 1500 | 34,468 | 51,739 | 119,398 |
| 1600 | 36,766 | 55,189 | 127,358 |
| 1700 | 39,064 | 58,638 | 135,318 |
| 1800 | 41,362 | 62,087 | 143,278 |
| 1900 | 43,660 | 65,536 | 151,238 |
| 2000 | 45,958 | 68,986 | 159,198 |
| 2500 | 57,447 | 86,232 | 198,997 |
| 3000 | 68,937 | 103,478 | 238,796 |