KENNETH KAUFMANN, ATTORNEY AT LAW

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Kenneth E. Kaufmann
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March 11, 2021

Via Electronic Mail

Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, OR 97308-1088
puc.filingcenter@state.or.us

Re: OPUC Docket No. UM 2118

Attention Filing Center:

Attached for filing in the above-captioned docket is Sunthurst Energy, LLC's Exhibit List and Supplemental Exhibits (Sunthurst/500-501). Confidential (Sunthurst/501) material will be will be provided to qualified parties under Protective Order No. 20-363 via encrypted zip file.

Thank you in advance for your assistance.

Sincerely,

Ken Kaufmann

Ken Kaufmann
Attorney for Sunthurst Energy, LLC

Attach.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UM 2118

SUNTHURST ENERGY, LLC, an Oregon limited liability company, Complainant, v. PACIFICORP d/b/a Pacific Power, an Oregon corporation, Defendant	List of Exhibits and Supplemental Exhibits offered as evidence by Sunthurst Energy

SUNTHURST EXHIBIT LIST

Exhibit 100 Opening Testimony (Daniel Hale)
Exhibit 200 Opening Testimony (Michael Beanland, P.E.)
Exhibit 201 List of Exhibits
Exhibit 202 Witness Qualifications Statement
Exhibit 203 One-Line Diagrams for Q0666, Q0747, and Q1045
Exhibit 204 Detailed Expenditure Reports for Q0666, Q1045, and OCS024
Exhibit 205 Q0666 Interconnection Studies
Exhibit 206 Q0747 System Impact Study Report
Exhibit 207 Q1045 Interconnection Studies
Exhibit 208 Q0666 Interconnection Agreements
Exhibit 209 PacifiCorp Interconnection Policies
Exhibit 210 [RESERVED]
Exhibit 211 Correspondences between Sunthurst and PacifiCorp
Exhibit 300 Daniel Hale Rebuttal Testimony
Exhibit 400 Michael Beanland, P.E., Rebuttal Testimony
Exhibit 401 PacifiCorp Responses to Selected Data Requests
Exhibit 402 PacifiCorp Interconnection Study Reports for NMQ0032 and NMQ0033
Exhibit 403 PacifiCorp System Impact Study Reports for Q0918 and Q0919
Exhibit 404 PacifiCorp System Impact Study Reports for OCS045 and OCS047
Exhibit 405 PacifiCorp Policy 138 Excerpts (12/20/20 rev)

SUNTHURST SUPPLEMENTAL EXHIBIT LIST

Exhibit 500 PacifiCorp responses to selected Data Requests received subsequent to filing of Sunthurst's Reply Testimony

Exhibit 501 PacifiCorp CONFIDENTIAL responses to selected Data Requests received subsequent to filing of Sunthurst's Reply Testimony

Dated this 11th day of March 2021.

By: Kenneth Kaufmann

Kenneth E. Kaufmann, OSB 982672
Attorney for Sunthurst Energy, LLC

Enclosure: Exhibit 500 (Confidential Exhibit 501 submitted separately)

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PUBLIC UTILITY COMMISSION

OF

OREGON

SUNTHURST EXHIBIT 500

PacifiCorp responses to Selected Data Requests answered after February 22, 2021

MARCH 11, 2021

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 1, 2021

Ken Kaufmann
Ken@kaufmann.law

RE: OR UM 2118
Sunthurst 11th Set Data Request (1)

Please find enclosed PacifiCorp's Response to Sunthurst 11th Set Data Request 11.1.

If you have any questions, please call me at 503-813-5934.

Sincerely,

____/s/___
Cathie Allen
Manager, Regulatory Affairs

UM 2118 / PacifiCorp
March 1, 2021
Sunthurst Data Request 11.1

Sunthurst Data Request 11.1

Please refer to PacifiCorp's 1st Revised Attachment 3.7-2, submitted by PacifiCorp to Sunthurst on February 12, 2021, and attached hereto.

(a) Who prepared the workbook (the original version) containing the four attached spreadsheets?

(b) How was the workbook used?

(c) Were values calculated in the spreadsheet utilized in PacifiCorp's 2017 IRP? If yes, please explain.

(d) Were values calculated in the spreadsheet utilized in derivation of PacifiCorp's avoided cost for Oregon Qualifying Facilities: (i) directly; or (ii) indirectly via the 2017 IRP or other source? Please explain.

(e) Define "surcharge" as that term is used in the four attached spreadsheets.

(f) Is "surcharge" defined the same in the four attached spreadsheets as "surcharge" is defined in PacifiCorp's Oregon interconnection Facilities Studies (for example in FS for Q0666 and Q1045)? If not, please explain the differences.

(g) Please provide the formula(e) for calculating Surcharge in Column M of the four attached spreadsheets (Column M is the column labeled "Surcharge").

(h) Other than the "Surcharge" applied in the four attached spreadsheets, is there any other way PacifiCorp's Capital Surcharge (as described in PacifiCorp's responses to DR 1.7, 1.15, and 1.16) is included in the cost of new resources included in PacifiCorp's 2017 IRP?

(i) Please explain PacifiCorp's statement, in response to DR 1.7 that "For projects of greater than $10 million, a capped surcharge rate is applied". How is the cap applied? What is the cap?

(j) For each of the resources described on the attached spreadsheets, please provide the assumed cost of interconnection and calculate the Capital Surcharge, as a percentage of the each resource's interconnection costs:

i. Resource 1 (200 MW Utah SCCT):

ii. Resource 2 (Oregon 436 MW SCCT):

iii. Resource 3 (Oregon 436 MW CCCT):

iv. Resource 4 (Wyoming Wind $1,637/kW):

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(k) Explain any differences between the Capital Surcharge rate applied to Q0666 and Q1045, on the one hand, and the Capital Surcharge rate applied to Resources 1-4, above, on the other hand.

(l) Explain any differences between the resulting Capital Surcharge (as a percentage of total project interconnection cost) applied to Q0666 and Q1045, on the one hand, and the resulting Capital Surcharge (as a percentage of total project interconnection cost) applied to Resources 1-4, above, on the other hand.

(m) Please state the person sponsoring the answers, above.

Response to Sunthurst Data Request 11.1

(a) File "Attach Sunthurst 3.7-2 1st REVISED," provided with the Company's 1st Revised response to Sunthurst Data Request 3.7, was prepared by PacifiCorp's resource development group. This group is separate from the transmission services department that evaluates generation interconnection requests.

(b) The values shown in file "Attach Sunthurst 3.7-2 1st REVISED" support the supply-side resource cost assumptions that were used in PacifiCorp's 2017 Integrated Resource Plan (IRP). Please refer to the 2017 IRP, Volume I, Chapter 6 (Resource Options), Table 6.1 (2017 Supply Side Resource Table (2016$))**,** and Table 6.2 (Total Resource Cost for Supply-Side Resource Options**)**.

(c) Yes. Please refer to the Company's response to subpart (b), above. Resources identified in the supply-side table were available for incorporation in portfolios selected by the system optimizer model (SO model) used in the 2017 IRP.

(d) After the acknowledgment of the 2017 IRP by the Public Utility Commission of Oregon (OPUC), docket LC 67, PacifiCorp's standard avoided costs were updated to incorporate values published in the 2017 IRP (from Table 6.1 and Table 6.2), and thus only indirectly rely upon the calculations provided in file "Attach Sunthurst 3.7-2 1st REVISED."

(e) In general, the surcharge shown in each of the four tabs in file "Attach Sunthurst 3.7-2 1st REVISED" is as described in Company's responses to Sunthurst Data Request 1.15 and Sunthurst Data Request 1.16. However, generation projects will have different rates as the capital expenses are tracked separately between generation and transmission/distribution projects.

(f) The definition of capital surcharge is the same as described in the Company's responses to Sunthurst Data Request 1.15 and Sunthurst Data Request 1.16. The actual rate may vary between generation and transmission projects.

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(g) The surcharge in column M in each of the four tabs in file "Attach Sunthurst 3.7-2 1st REVISED" was obtained by multiplying the then-current capital surcharge rate for generation project and the cost of construction before financial costs for each period. For generation projects, the capital surcharge is limited to a maximum of $500,000. If the generation resource project exceeds the maximum limit, the rate is adjusted to reflect the maximum limit.

(h) Yes. The information in file "Attach Sunthurst 3.7-2 1st REVISED represents rates and maximum limits for surcharge associated with generation projects. Part of the generation project costs are expenses associated with generation interconnection costs (transmission/distribution network improvements for interconnection). Surcharge is applied to transmission/distribution improvements as described in the Company's responses to Sunthurst Data Request 1.15 and Sunthurst Data Request 1.16.

(i) For transmission and distribution projects, including transmission and distribution improvements to accommodate generation interconnection requests, the surcharge is capped at ¼ of the full rate for turnkey expenses. For example, in 2020, the full surcharge rate for estimating purposes was 8 percent. If the total direct costs is greater than $10 million, the turnkey expenses would be capped at 2.5 percent. These would result in projects having a capped rate between 2.5 percent and 8 percent. This is different for generation projects (i.e. construction of generating facilities). For generation facilities, the rate is also capped ¼ of the full rate for turnkey activities, but it has a maximum limit of $500,000. It is important to note that expenses for building a new generating plant are usually all turnkey expenses and surcharge is generally governed by the maximum limit due to the large capital investment required to build a new power plant. Since new power plants can cost more than $100 million, the capital surcharge could be less than 1 percent as shown in three of the four examples provided. It is also important to note that typically for turnkey projects, engineering, procurement, and construction are conducted by contractor(s) and not done by internal PacifiCorp personnel, which leads to a lower surcharge percentage being assigned to projects greater than $10 million.

(j) The estimated electrical interconnection costs for the proxy resources in tabs "Resource 1," "Resource 2," and "Resource 3" of file "Attach Sunthurst 3.7-2 1st REVISED" was $12,091,000 for each proxy resource. The estimated collector substation, interconnection substation, transmission interconnection, and network upgrades costs for the proxy resources in tab "Resource 4" of file "Attach Sunthurst 3.7-2 1st REVISED" was $9,960,000. These are high level costs prepared by PacifiCorp's resource development group and do not have enough detail to identify the surcharge amount. These four projects are only a few of the many projects identified in the IRP. If PacifiCorp's energy management department selects any of these projects to move forward, a generation interconnection request would be submitted, and a study and detailed cost would be provided similar to the study provided to Sunthurst Energy, LLC (Sunthurst). PacifiCorp's generation interconnection department would make the same assumptions regarding capital surcharge for projects submitted by PacifiCorp's energy supply department or a third party customer such as Sunthurst.

(k) As explained above, the rate used for estimating capital surcharge for Q0666 and Q1045 was 8 percent of the total direct cost. Both projects require network improvements, and both have less than $10 million in direct capital costs. As such, the full 8 percent surcharge rate is applied. In regard to the four generating facilities identified in the IRP, the three projects that vary in capital costs between $124 million and $498 million, the rate is governed by the maximum $500,000 limit. For the project that is about $19 million in capital costs, the surcharge rate is 2.5 percent as all costs are all considered turnkey.

(l) There would be no difference in assumptions for Q0666/Q1045 and the costs associated with interconnection improvements for the four generating facilities identified. After a generation interconnection study is completed, if the costs are less than $10 million, a surcharge rate of 8 percent would be assumed for estimating purposes. If the generation interconnection improvement is more than $10 million in direct costs, the turnkey costs would be capped, and the result rate would be between 2.5 percent and 8 percent. The 8 percent rate may be different depending when the study is completed as the assumed estimating rates do vary by year.

(m) Dan MacNeil, Grant Laughter, and Alex Vaz

Note: PacifiCorp's IRPs are publicly available and can be accessed at the following website link:

https://www.pacificorp.com/energy/integrated-resource-plan.html

Respondent(s): Dan MacNeil / Grant Laughter / Alex Vaz

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 1, 2021

Ken Kaufmann
Ken@kaufmann.law

RE: OR UM 2118
Sunthurst 12th Set Data Request (1)

Please find enclosed PacifiCorp's Response to Sunthurst 12th Set Data Request 12.1. Also provided is Attachment Sunthurst 12.1.

If you have any questions, please call me at 503-813-5934.

Sincerely,

____/s/___
Cathie Allen
Manager, Regulatory Affairs

UM 2118 / PacifiCorp
March 1, 2021
Sunthurst Data Request 12.1

Sunthurst Data Request 12.1

Please refer to PacifiCorp's response to DR 10.4(d):

> *"PacifiCorp standard is to use LDC settings when controlling voltage on its distribution system. Please refer to Attachment Sunthurst 10.4, which is Section 7.D from the Pacific Power Engineering Handbook 1E.3.1 – Distribution Planning Study Guide. 7.D regards regulator control settings".*

(a) Please provide a complete copy of the Pacific Power Engineering Handbook 1E.3.1, referenced in the above answer. Please provide the 17 Dec 15 version, as well as the current version, if different.

Response to Sunthurst Data Request 12.1

Please refer to Attachment Sunthurst 12.1 for the Engineering Handbook 1E.3.1 Distribution Planning Study Guide in its entirety. This is the "17 Dec 15" version as requested and is also the current version of the document.

Respondent(s): Douglas Guttromson

1E.3.1—Distribution System Planning Study Guide

1. Scope

This study guide addresses the topic of how to perform a distribution system planning study, which is a process used to periodically examine a selected portion of the primary distribution system. The study is used to identify construction or maintenance items due to a change in load or an unacceptable decrease in system reliability. The approved study becomes a recommended construction plan. The capital budgeting process relies on the distribution system planning study report for supporting information and for multiyear capital forecasting.

2. General

The study normally covers a period of two to ten years to provide a long-term perspective for the area. The study includes an evaluation of the electrical, operational, and economic performance of a group of circuits and the substations serving them. System expansion and upgrades included in the planning study are based on company-approved standards or guidelines.

A distribution system planning study relies upon exchanging information with other groups. Various resources can provide valuable input for load forecasting and system modeling. The study plan affects other groups within the company who should be included in the development and approval of the plan.

The construction plans in the Distribution System Planning Study must be coordinated with the transmission system planning study. Normally the distribution study focuses on items on the load side of the distribution substation. However, the distribution substation equipment and its limitations often become an integral part of the distribution study. Where upgrade of substation transformer and equipment capacities are required to serve the distribution system or to resolve problems at the distribution level, both the distribution and transmission planning studies need to reflect the proposed construction.

The study system is comprised of one or more distribution substations and the corresponding primary circuits. Typically, multiple substations and circuits interconnected at the distribution level are studied as a system, because the solutions to specific problems may affect other substations, circuits, or solutions.

This study guide promotes consistency in the method, procedure, planning criteria, and content of distribution system planning studies.

3. Definitions and Abbreviations

The following definitions and abbreviations pertain to this study guide.

ANSI — American National Standards Institute

ASPEN OneLiner — an application produced by ASPEN, Inc. which models the company transmission system down to the substation low-side busses. Field engineers use ASPEN's "Relay

Group" to coordinate distribution overcurrent protective devices, as well as source impedances used in FeederAll.

base year — the latest year that actual load data is available

circuit performance index (CPI) — a measurement of distribution feeder reliability that takes into account the following: outage duration, feeder customer count, number of sustained outages, number of momentary outages, and frequency of feeder breaker lockouts. The CPI is normalized so that all PacifiCorp feeders can be compared.

CML — customer minutes lost

critical limiting factors — equipment ratings and operating practices that significantly limit the ability of feeders and substations to serve load. For example, a small conductor between feeders might limit the ability of one feeder to serve load on the other feeder.

CSF — case study file

DPAD — Distribution Planning Asset Database; a Microsoft Access database used by Field Engineers and Asset Management to maintain data and budgetary information for the distribution system and construction projects. DPAD is used to create Expenditure Requistions and to print portions of the planning study.

DSPSG — Distribution System Planning Study Guide

end year — the last year of the study period

FeederAll — a power flow application produced by ABB, Inc., used by Field Engineers to model the distribution system

load factor — the ratio of the average load over a designated period of time to the peak load occurring in that period

loss factor — an empirically-derived constant that relates load factor to energy

LTC — load tap changer

ORG — Operability and Reliability Guideline

Power Drive — a network drive located at \\SLCSHRN102\SHR02\PD\POWER and commonly mapped to X: on network machines. Field Engineers store department-related documents in this folder.

risk assessment — evaluation of the adverse impacts of exceeding planning guidelines; a method to compare consequences of alternate solutions

SCHOOL — Substation and Circuit History Of Operational Loading; a database of historical reads on substation transformers, busses, and feeders. SCHOOL data is accessed though Datalink —an Excel add-in — and ProcessBook. Both Datalink and Processbook use the PI System, a product of OSIsoft, Inc.

study cycle class — a measurement of how long a completed planning study remains valid (and therefore how often or how soon it should be redone), for line construction and budget preparation. Flow charts in the Distribution System Planning Study Guide (Figure 2 and Figure 3) are available to help determine the study cycle class.

study period — the time-frame during which the distribution system will be evaluated. This period is usually at least two years, and may be extended to ten years.

4. Study Guide Organization

The remainder of this guide is divided into five sections. It also references forms, tables, spreadsheets, and other tools that are available to assist the engineer in completing a planning study. Electronic forms of many of these tools are available on the Power Drive, in the "Studies" folder. A list of these forms and tools is found in Section 10, Computer Resource References.

Section 5 provides a brief overview of how to complete a study. It is intended as a quick reference to an engineer who is familiar with the study process.

Section 6 covers data collection and system modeling.

Section 7 deals with system analysis and determination of potential system problems.

Section 8 discusses the steps involved in developing a construction plan to solve problems identified in Section 7. This includes proposal of possible solutions and the selection of the best solution.

Section 9 describes the creation of the Distribution System Planning Study Report.

Section 10 identifies computer resource references.

5. Outline of Study Procedure

This section includes an outline of recommended steps to complete a planning study. A flow chart (Figure 1) shows a logical sequence of these steps.

5.1. Checklist for Distribution System Planning

- ❑ Identify substations or circuits in study area.
- ❑ Discuss study update with Operations Manager and Area Planning.
- ❑ Gather data and update load flow model to current operating configuration.
- ❑ Run base-year study.
- ❑ Forecast load growth:
    - ❑ Identify new loads.
    - ❑ Identify growth pattern or direction.
    - ❑ Calculate historical growth for area.
    - ❑ Create Load Forecast Table.
- ❑ Determine study period.
- ❑ Study end year:

- ❑ Apply forecast loads to computer model.
- ❑ Run end-year study.

❑ Identify potential operating problems:

- ❑ Overloaded equipment and circuits
- ❑ Voltage problems
- ❑ Power factor problems
- ❑ Protection problems
- ❑ Critical limiting factors
- ❑ Reliability problems
- ❑ Regulatory problems
- ❑ Power quality problems
- ❑ Other

❑ Identify solutions:

- ❑ Apply solutions to end year.
- ❑ Evaluate alternate solutions for end year.
- ❑ Evaluate economics of each solution.
- ❑ Establish a time line for each solution.
- ❑ Evaluate feasibility of solutions.
- ❑ Select optimal solution.

❑ Determine study class.

❑ Publish Distribution Study:

- ❑ With DPAD:
  - ❑ Enter solutions.
  - ❑ Publish construction plan and approval.
  - ❑ Prepare description and study summary.
- ❑ With Microsoft Excel: Prepare load forecast with load forecast template.
- ❑ With Microsoft PowerPoint: Develop sketch or diagrams.
- ❑ With Adobe Acrobat: Compile all study documents into one file.

- ❑ File supporting documentation.

❑ Route Distribution System Planning Report for approval:

- ❑ Field Engineering Support for review
- ❑ Wires Manager for approval
- ❑ Area Planner, Regional Community Manager for their information

❑ Present report to Study Approval Team when scheduled, to obtain final approval on completed study.

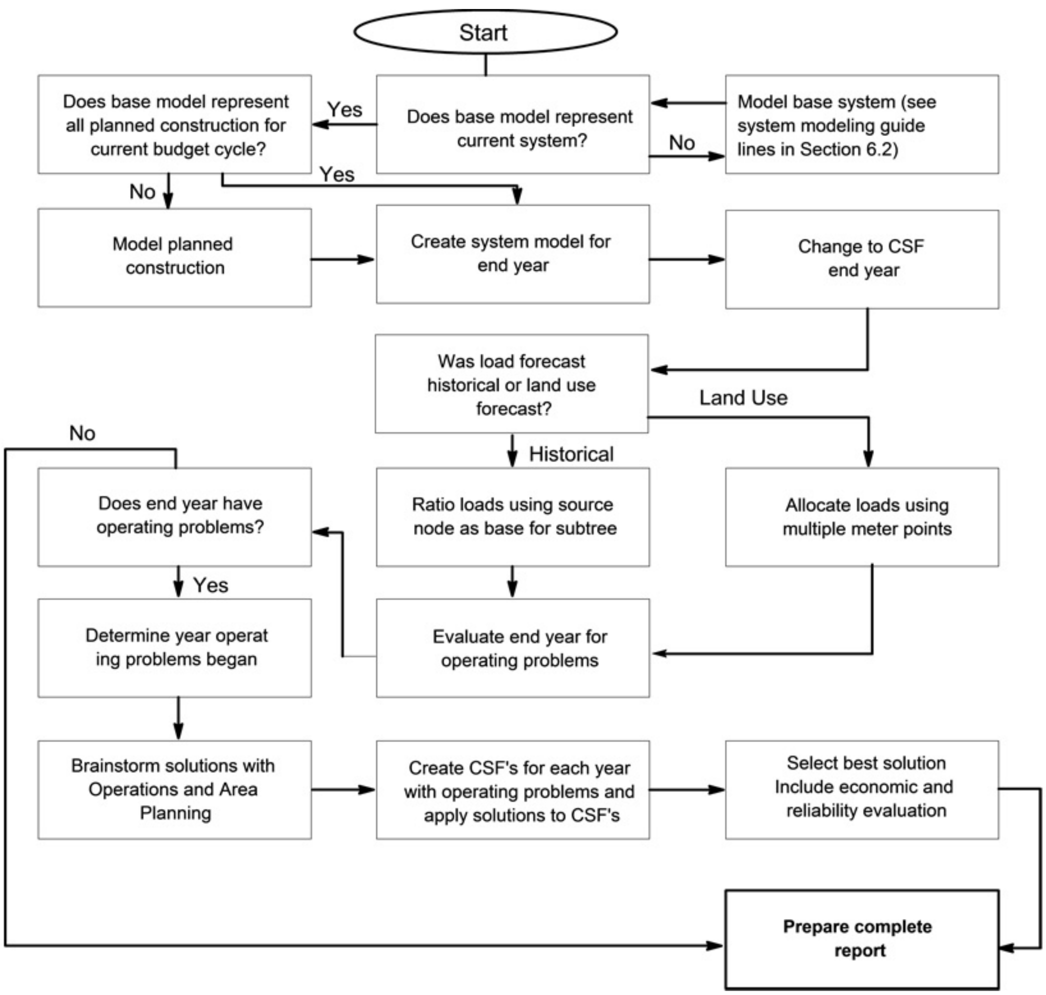

Figure 1—Distribution Study Procedure Flowchart

6. Data Collection and Modeling

6.1. Study Area Determination

Study areas are defined in DPAD. In some cases, the study characteristics may have changed drastically, and a new study area needs to be determined. For example, a study area that has seen large capacity increases is now too large to manage as one study. Any change to the study area shall be coordinated with the field engineering support engineer, who will make the necessary changes in DPAD.

Study area changes should be based on the following guidelines:

1. Break the system model down into logical study areas. A study area may include multiple substations and circuits or a number of small geographically isolated areas. The study area should include a complete system where switching between substations and circuits is practical.
2. Where it is not practical to do a comprehensive study on the logical study area, such as the Salt Lake and Ogden metro areas, the study area should be divided into manageable study areas.
3. Where separate voltages are involved, different studies may be performed on each voltage level. If voltage conversion, or step-down transformers are involved, the levels should be studied together.
4. Commercial or industrial underground areas that are part of a larger study area may be covered with a separate study, such as downtown underground systems.

6.2. System Modeling Guidelines

FeederAll is the standard distribution system modeling program. Specialized programs are also used to model areas such as the Portland and Salt Lake City underground networks. Care should be taken to verify the model represents the study area as it actually exists. In-person fielding of open points should be performed for all urban circuits. In addition, fielding should be performed if the growth rate is greater than 2% or if there are new substations/circuits since the last study. The quality of the Distribution System Planning Study is a function of the base year model. The more accurate the model, the more accurate the study results. The engineer should refer to the FeederAll User Guide (available in the Help menu) for detailed explanation on how to model the system.

A thorough explanation of how to model a study area with FeederAll is beyond the scope of this document. FeederAll training documents are available on the Power Drive in the \FeederAll\Documentation folder. Developing an accurate FeederAll model commonly involves the following steps:

1. Add any additional nodes and circuit segments to the model to represent the study area's configuration correctly.
2. Verify that the existing segments represented in the study area match what is built in the field.
3. Verify that the connected load at each node is correct. Using circuit maps, add up the connected kVA around each node by phase, and confirm the numbers with those already in the study area model. Modify any load numbers that are not correct. Input, update, or remove spot loads from the base model as needed.

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4. Verify capacitor and regulator placement. Make sure the associated settings are correct. Make sure capacitors are modeled correctly as either fixed or switched capacitors.
5. Verify that the FeederAll model is using the current economic parameters. The FeederAll parameters in Oracle will be updated by Engineering Support annually.
6. Determine the peak loading for the circuit (or source) from actual metered data. Select a peak that properly matches normal operation. Verify circuit switches are modeled in the correct open or close position at the time of the peak. Sometimes an inappropriate peak value is created by switching to accommodate maintenance work. Apply the appropriate peak load to the model. Where the source node represents multiple circuits use multiple meter points to allocate load on each circuit.
7. Verify recloser or relay settings and fuse sizes are modeled properly.
8. PacifiCorp uses standard conductor ampacity limits in their computer models. A discussion and associated spreadsheet (Ampacity.xla) on how to calculate ampacities for other than default ambient conditions is on the Field Engineering wiki on the company intranet, at http://ampsportal/wiki/ow.asp?AmpacityCalculation.

6.3. Significant Assumptions

Each study is based on certain assumptions unique to the study system. The value of the study will be greatly enhanced if these assumptions are clearly understood by the users of the study. Any significant assumptions can be summarized into a brief statement or list, which may be included with the study documentation (see Section 9.1). This section provides an abbreviated listing of significant assumptions commonly used in distribution system planning studies.

1. Load forecast assumptions:
   a. political factors
   b. local economic outlook
   c. local growth pattern and duration
2. System operation assumptions:
   a. nominal voltage(s)—potential voltage conversion
   b. deviations from corporate standards
   c. completion of planned projects—cancellations, delays, budget constraints, or changes in scope of current projects
   d. equipment settings
3. System power factor assumptions:
   a. power factor targets
   b. distribution capacitors vs. substation capacitors vs. customer capacitors

4. System reliability assumptions:
   a. allowable CPI
   b. allowable CML
   c. contingency planning basis
   d. allowable complaint levels
   e. critical customers—special reliability requirements
   f. operating life of equipment
5. System study assumptions:
   a. data gathering methods
   b. system modeling
   c. study process

6.4. Load Forecast Methods

This section describes different methods of load forecasting. Load growth can be forecast using three different methods: historical load growth projection, land use forecasting, or a combination of historical trend and land use forecasting. Although load growth is usually positive, occasionally it may decrease. Each circuit in a study area will usually use the same load forecast method, but it is not a requirement. Each circuit in the study area can use a different load forecast method based upon its specific growth patterns. After a study period has been established, load should be forecast for each year of the study period.

At a minimum, load forecast should be determined from historical kW load growth using a linear regression over a minimum of five years. Historical load growth should be projected into the future five years beyond the base year and adjusted for new large loads and load transfers. Consideration should be given to affected adjacent substations. Load forecasts also need to agree with Area Planning forecasts. Load forecasting tools and detailed instructions are available on the Power Drive under Tools and Papers\Load Forecasting.

6.4.1. Historical Load Forecasting

Linear and exponential load forecasting, also called trending, assume future load change resembles past load change and can be projected from historical peak data. When the study area has small load growth or the load change is uniformly distributed this method may be used with a high degree of confidence. A formula for this method is shown in Eq (1).

$$GR = \sqrt[N]{\frac{FD}{ID}} - 1 \qquad \text{Eq (1)}$$

where

GR = Annual growth rate
FD = Final year demand
ID = Initial year demand
N = Number of years

Other forms of historical trend load forecasting such as linear regression can be used. Microsoft Excel has many functions that aid in regression analysis.

6.4.2. Land Use (Spatial) Forecasting

Land use forecasting requires more work than the trending growth method, but is more accurate for areas with rapid or nonhomogeneous load changes. The intent of the land use forecasting method is to forecast load changes based on political and economic forces in a study area. Land use forecasting is based on understanding the factors associated with load change. Land use forecasting is typically done with a computer program specifically designed for that task and is more commonly done on a transmission-level study.
See http://ampsportal/wiki/ow.asp?AmpacityCalculation.

Questions the engineer might consider when using the land use forecasting method are:

1. What parts of the study area have reached load saturation? What parts of a circuit or substation have reached saturation?
2. What known industrial or large commercial loads will be added in the study area? How will these loads affect employment or residential growth in the area?
3. Have certain parts of a study area been re-zoned?
4. Have city boundaries been changed? How many circuit miles will be purchased by municipalities?
5. What is the housing market like in different parts of the study area?
6. What infrastructure will be completed during the study period? What effect will it have on the direction of load growth?
7. How much undeveloped land exists for different parts of the study area? What types of load will be developed?

When the real sources of load change in a study area are identified, the results of the Distribution System Planning Study will be more accurate.

6.4.3. Hybrid Forecasting

The last method of load forecasting is a hybrid method combining trending and land use forecasting. This method accounts for trending associated with homogenous load changes and incorporates elements of land use forecasting. This method is the most practical for areas with rapid load change where the study area has not reached its final land use.

To implement this method, first project load changes using the trend projection method. Next, adjust the magnitude and distribution of the forecast load to accommodate expected land use changes.

6.5. Determining the Study Period and End Year

After determining the appropriate load growth forecast method, the engineer should determine the time frame for which the study system will be evaluated. This time frame is called the study period. The study period starts with the base year, which is the latest year for which load data is available, and extends five construction years into the future.; The end year is the final year of the study period.

7. System Analysis and Problem Identification

7.1. Applying Forecast Load to the Distribution Model

Once the study period, the end year, and the load forecast have been determined, the end year load forecast is applied to the distribution model. This will be used to evaluate the distribution system for potential problems during the end year. If there are problems in the end year, solutions will need to be identified, and the appropriate year for implementation determined.

Forecast load can be applied to the system model in two ways. The first method is to ratio the loads at all nodes. This can be accomplished by entering a multiplication factor into the computer model, which will increase or decrease the load at each node. This method is best when load is forecast using a trending method.

The second method requires the engineer to model multiple meter points on each circuit to reflect the load growth on selected portions of the circuit. After the meter points have been modeled, the load on the circuit is allocated. The computer model will use the meter points to allocate loads properly on the circuit. This method is best when load is forecast using a land use forecast method.

7.2. Distribution System Planning Criteria

Table 1 provides a quick reference to the appropriate planning criteria for a variety of system components and conditions.

Table 1—Distribution System Planning Criteria Reference Table

Category	Criteria
Substation Transformer Capacity	Engineering Handbook 1B.4, System Reliability Criteria
Substation Regulator Capacity	Summer rating: 1.05 x top nameplate rating for OA & OA/FA; Winter rating: 1.33 x top nameplate rating for OA & OA/FA
Substation Circuit Equipment Capacity	nameplate ratings
Line Protective Device Capacity	nameplate rating(s)
Line Regulator Capacity	Use substation regulator capacity criteria.
Step-up or Step-down Transformers Capacity	Engineering Handbook 1B.4, System Reliability Criteria (Use substation transformer capacity criteria.)
Steady State Voltage Level	Engineering Handbook 1B.3, Planning Standards for Voltage
Transient Voltage Level	Engineering Handbook 1C.5.1, Voltage Fluctuation and Flicker
Voltage Balance	Engineering Handbook 1C.3.1, Voltage Balance
Primary Circuit or Substation Power Factor	Engineering Handbook 1B.3, Planning Standards for Voltage
Circuit Reliability	Engineering Handbook 1B.4, System Reliability Criteria
Circuit Harmonic Conditions	Engineering Handbook 1C.4.2, Harmonic Distortion—Utility Engineer Guidelines

7.3. Detail of System Problems

This section discusses significant system problems identified as a result of the engineer's analysis of the system. It provides ideas for an optional supporting document detailing potential system problems. The following sections in the guide cover more detailed descriptions of the specific types of problems that are usually found on a system, and how to determine whether they will occur.

The detail of system problems helps to explain the course of action chosen in the plan, and to justify any resulting budget projects. The system problem details may be included as supporting documents accompanying the study report. Organize the presentation to make an easily identifiable connection between the data or study and each system problem identified.; Some types of system problems are best studied and presented on a circuit or substation basis, whereas other problems are best studied and presented by type.; Reference the system problem details to the proposed construction item.

The detail of system problems could include:

1. analyses of metering or other types of data showing the nature of the problem
2. copies or summaries of computer model results
3. applicable graphs and tables

4. references to applicable standards and guidelines
5. detailed description of each system problem:
   a. nature — what it is
   b. scope — which circuit(s) and/or substation(s) are affected
   c. time line of occurrence(s) of problem

7.4. Operating Problem Identification

The identification of operating problems is based on the engineer's knowledge of the distribution system. Some tools for operating problem identification are the study's base year and end year computer models, the Engineering Handbook guidelines and criteria, actual voltage and current measurements, and other field observations. Three areas for operating problem identification are environmental factors, operating performance, and system configuration changes as described below in Sections 7.4.1 through 7.4.3.

The possible problems on a distribution system are not limited to the three areas discussed here. Other operating problems may be identified, based on the engineer's experience and knowledge of the distribution system.

7.4.1. Environmental

The winter and summer loading guidelines in the engineering handbook apply to both winter and summer peaking distribution systems. Do not assume that a winter peaking system will not have summer operating problems, or that a summer peaking system will not have operating problems during the winter.

Ambient summer and winter temperatures outside the temperature range used for developing loading guidelines will affect equipment heat dissipation and change conductor impedances. Extremely cold winter temperatures increase heat dissipation and reduce conductor impedances. Equipment loading limits may be increased if temperatures are consistently cold. Or, if the extremely cold temperatures are infrequent, the prudent action may be not to use the extreme winter peak. Extremely hot summer temperatures reduce heat dissipation and increase conductor impedances. Reduce equipment loading limits if the extreme hot summer peak is consistent. Refer to Section 7.5, Equipment Capacities, for more information.

High elevations reduce heat dissipation, resulting in lower equipment loading limits. Refer to Section 7.5 for more information.

Contamination causes corrosion on contact surfaces, reducing load-carrying capacity on switches and connectors, and reducing insulation levels. Sources of contamination include: salt fog near large bodies of salty water, sulfur gases near oil fields, industrial fallout, and wildlife scat.

7.4.2. Operating Performance

Substation transformers operated in parallel may not have the full combined capacity of the individual transformers, due to unequal load split on the transformers.

Current unbalance must be considered when checking equipment capacities. Some equipment guidelines, such as the conductor guidelines, allow for some current unbalance. Tools for identifying current unbalance are computer study load flow, monthly substation current demand reads, and recording ammeters. Remember that meter readings are not infallible.

Excessive voltage unbalance is undesirable in the distribution system. Three-phase equipment such as motors are sensitive to voltage unbalance. Voltage unbalance may not be a problem in areas that serve only single-phase loads. Tools for identifying load unbalance are computer study load flows and recording volt meters. Refer to Section 7.8 for more information.

Steady-state voltage should remain within guidelines at the point of delivery through normal load variations. Primary voltage excursions above or below guidelines can be acceptable in areas without customers. Check for high voltage where regulator settings have not been changed to accommodate added load, or are affected by current unbalance (see Section 7.8 for more information).

Indications of a harmonic problem on a distribution circuit are frequent capacitor fuse blowing, and excess heating of transformers not attributable to load. Possible sources of harmonic problems include industries with variable-speed drives, and customers with a high concentration of electronic equipment. For more information on harmonic loads, see Engineering Handbook 1C.4.2, *Harmonic Distortion—Utility Engineer Guidelines*.

7.4.3. System Configuration Changes

Load transfers require another analysis of the system. Items to check are voltage levels on the affected circuits, effects of the load transfers on subtransmission, proper overcurrent protection, and the physical condition of the circuit carrying the added load.

The condition of the circuit picking up load is best analyzed before the load transfer is made. Equipment such as cutouts and connectors may have deteriorated over time, and could overheat with the added load. Conductor sag may be a problem if the line was designed for a maximum operating temperature less than current standards. For example, a conductor operated at 176°F will have excessive sag if it was installed for clearances based on a 140°F conductor operating temperature.

Check the effect of the system configuration change on voltage-regulating devices. Review the regulator compensation settings and the capacitor switch points on the affected regulators and capacitors. Also check the voltage swing caused by capacitor switching on the new configuration.

Load transfers often occur between substations and different parts of the subtransmission system. Obtain input from the area planning engineer concerning subtransmission capacity.

Load transfers will also affect the circuits' overcurrent protection. Check loading through protection devices and check the coordination between these devices.

A change in the system configuration also changes the reliability to the customers affected by the load transfer. An example is increasing the number of momentary operations by transferring a rural area with high tree exposure to a suburban residential area.

The possible problems on a distribution system are not limited to the three areas discussed here. Other operating problems may be identified, based on the engineer's experience and knowledge of the distribution system.

7.5. Equipment Capacities

Accurate assessment of distribution equipment capacities is crucial to system planning. Responsibility for this function as it applies to distribution substations is shared between Field Engineering and Area Planning Engineering. Field Engineering and Area Planning should always consult and work together when the need for a substation equipment upgrade is determined or when equipment ratings are in question.

Meter readings and their corresponding multipliers must be verified for accuracy before use in a system study.

Equipment capacities may not match the equipment nameplate. Various factors contribute to this discrepancy, such as elevation and ambient temperature, field modifications, previous usage (loading history, through fault history, duty cycle history, maintenance history), and factory defects. Detailed information on loading guidelines can be found in Engineering Handbook 1B.4, *System Reliability Criteria*. Sections 7.5.1 through 7.5.8 list various types of equipment, with comments on the determination of capacity ratings for each.

7.5.1. Substation Transformers

Substation transformers usually come with one to four sets of capacity ratings. Each set of substation-class transformer ratings usually includes one rating based on a 55°C rise over ambient temperature, and another based on a 65°C rise, for each of the following designations, if applicable:

1. OA (oil-air, or natural convection cooling, using the cooling fins and tank construction of the transformer)
2. FA (forced air, or fan-cooled, where a single set of fans is mounted on the cooling fins)
3. FAA (a second set of fans is mounted similarly to the first, significantly improving capacity over the first set alone)
4. FOA (forced-oil and forced-air, by means of an oil circulation pump usually mounted near the base of the transformer, in addition to the above fans)

Some older transformers lack forced-air equipment, and most distribution substation transformers lack forced-oil capability.

Transformer ratings "gotchas" and solutions for determining effective ratings include:

1. nameplate limitations

   If a transformer nameplate shows only a 55°C rating, it should not be assumed that it has a corresponding 65°C rating, because it may not have been constructed to handle the extra heat transfer. Likewise, if the transformer nameplate shows only OA ratings, do not assume that the transformer will have standard FA/FAA/FOA ratings.

2. temperature and altitude considerations

   Substation transformers are designed to operate under specific ambient temperature and altitude conditions. Spare substation transformers when placed into service should have their ratings verified for the temperature and altitude of their new location.

3. determining effective ratings

   Ratings are best determined by consulting the original manufacturer's test data sheets or specifications. If these are not available, provide the manufacturer a serial number and photograph(s) of the unit in question, showing cooling equipment and position. Substation Engineering may help locate successors of out-of-business manufacturers to obtain this information. Manufacturers are often able to provide relatively low-cost fan kits or other equipment to help upgrade transformer ratings in the field.

4. paralleling transformers

   If transformers are operated in parallel, their impedances may not be matched. In this situation, the load split must be determined by calculations based on impedance ratios.

5. new transformer sizing

   Transformer sizing is subject to an economic evaluation. Often the economic evaluation will result in a transformer at least two standard ratings larger than the projected peak load. PacifiCorp uses Engineering Handbook 1B.4, *System Reliability Criteria*, as the basis for *redline* (time to upgrade substation transformer) purposes.

   The engineer should evaluate the following with respect to substation transformer capacity:

   a. physical presence of any specified cooling equipment (before assuming the capacity rating designated on the nameplate is valid)

   b. altitude of substation

   c. average summer high or winter low ambient temperature at the substation during peak

   d. transformer load or duty cycle

   e. maintenance history

   f. manufacturer's certification of capacity

   g. availability of additional cooling equipment

ROCKY MOUNTAIN POWER

PACIFIC POWER

7.5.2. Substation Regulators

The following items should be considered when evaluating substation regulator capacities:

1. ratings

   Industry standard for voltage regulators is a nameplate kVA rating of 10% of actual capacity, and they are usually OA-rated only. A current throughput rating is usually also provided on the nameplate. Regulators are sometimes forgotten when circuits are reconfigured. Experience has shown (and manufacturers corroborate) that regulators are usually only able to serve up to their nameplate capacities during summer months without loss of life. Since they fail more often than any other equipment type, it is essential to consider their ratings carefully in an area plan.

2. matching of substation transformer and regulator sizes

   Matching of substation transformer and regulator sizes is recommended, because the protection for this equipment is typically designed for the transformer and may not adequately protect regulators that have capacity great enough for existing loads but less than the transformer.

3. extending regulator ratings

   If the system on which regulators are being used needs less than the full 10% regulation, a 'load-bonus' feature on some of them may allow up to a 60% increase in capacity at ±5% regulation, and will allow lesser capacity increases for in-between regulation range settings.

   The engineer should evaluate regulator capacities by considering:

   a. load cycle versus regulator capacity rating

   b. number of total operations of tap changer

   c. regulator control settings

7.5.3. Substation Circuit Breakers, Circuit Switchers, and Reclosers

There are typically two nameplate ratings. The first is for continuous or load current, and the second is for short circuit interrupting capability. It is necessary to ensure that fault interrupting devices have sufficient load ratings. It is equally important that the interrupting ratings remain sufficient for the maximum fault duty. System upgrades that decrease source impedance must include consideration for the fault interrupting devices. Bus tie breakers must have ratings at least equal to those of the highest rated line breaker for which they will substitute, and must be rated to carry the load with one substation transformer out of service.

The engineer should evaluate the following related to equipment capacity:

1. load cycle

2. duty cycle (number of operations)

3. maintenance history

4. system impedance or available fault duty versus interrupting rating
5. the need for over-rated equipment at other system locations

7.5.4. Substation Switches

The nameplate rating is expressed in continuous current amperes and in short circuit duty amperes. The short circuit rating is not an interrupting rating but is the rating of the closed switch only.

The engineer should evaluate the following:

1. load capacity versus possible switch loading
2. short circuit duty

7.5.5. Substation Bus Work and Jumpers

Jumpers might not have the same current-carrying capacity as the bus work to which they are connected. The capacities of both should be evaluated in the study, and necessary changes recommended. Jumpers, or bus work changes should accommodate loading requirements at the substation.

7.5.6. Line Transformers

These include all transformers that directly serve customers as well as those that step primary distribution voltage up or down to provide additional line capacity.

The engineer is advised to evaluate the following with respect to transformer capacity:

1. load or duty cycle
2. ambient temperature conditions

7.5.7. Line Conductors

(See Distribution Construction Standards GB 011, Underground Primary Cable and Accessories—Cable, and EC 051, Overhead Primary Conductor—Ampacity.)

Conductor ampacity is sensitive to ambient conditions. The standard conductor ampacity limits may be changed to accommodate special situations, such as high altitude or extreme ambient temperatures. A discussion and associated spreadsheet on how to calculate ampacities for other than default ambient conditions is on the Field Engineering intranet page (see Section 10).

Conductors that have been damaged by overloading or physical mishandling do not have the same ratings as undamaged conductors.

The engineer should evaluate the following related to line conductor capacity:

1. load or duty cycle history
2. ambient temperature and elevation
3. corrosion

7.5.8. Line Switches

The capacity of line switches, gang-operated or blade, needs to be addressed when considering the loading of distribution lines. Possible limitations include both steady-state current and fault capability. Where switches are used to transfer load, the switch must be able to break the loop current flow.

7.5.9. Jumpers

The current ratings of jumpers and connectors should meet or exceed the capacity of the associated line equipment.

7.6. Reliability

Circuit reliability problems can be evaluated using the circuit performance index; customer minutes lost (CML); the number of breaker operations; the number, frequency and duration of outages; complaints from customers; or requests from utility regulating agencies. Reliability improvement projects may be identified in a planning study, or through other company programs.

7.6.1. Circuit Performance Index

Additional information can be obtained from the outage reporting system.

7.6.2. Circuit Reliability Problems

Circuits can be exposed to extreme weather conditions such as temperature, snow, ice, wind, and lightning. Possible solutions to weather-related problems include decreasing span lengths, changing the type of construction (underground, overhead, spacing, grade, etc.), or relocation of lines. In areas subject to lightning, proper application and installation of lightning arresters can reduce outages and damage to facilities. Effective system grounding is crucial to the proper operation of arresters.

Lines may also be subject to trips and outages due to birds, rodents or other animals. This problem may be mitigated by changing the type of construction or by using raptor or small animal safeguards. See Distribution Construction Standards Section EV, Bird Protection.

A common cause of interruptions is trees and limbs near lines. Vegetation management, including trimming and removing trees, is preferred. However, some problems can be solved only by line relocation or conversion to underground.

If dust or salt contamination is the cause of outages, solutions include instituting a cleaning and maintenance program, reinsulating to a higher voltage rating, changing insulation materials, undergrounding, or relocating the line.

7.6.3. Protective Devices

Circuit breakers and line protection devices serve to minimize the scope of outages and to limit damage to facilities. Settings should be reviewed, and protection coordination changed, if necessary, to insure proper operation of all protective devices.

Reliability problems may be caused by equipment failure, overloading, or improper settings. Equipment that fails should be repaired and maintained, or replaced. Overloaded equipment should be replaced or relocated. Equipment settings should be reviewed and changed if necessary.

The installation of devices such as switches, fuses, SCADA and fault indicators assists in outage management. These devices can be useful in determining the location of an outage, reducing its scope and duration, and expediting restoration of service.

7.6.4. Reliability Priorities

Priorities for reliability improvement should be as follows:

1. safety and protection of life and property
2. preservation of company facilities
3. continuity of service
4. power quality

Different types of customers have different reliability needs, that should be considered when prioritizing corrective measures. A reliability problem may be solved by switching a sensitive or priority load to another circuit. Adding a new circuit may be the preferred solution in some situations. Substation maintenance or a substation rebuild may be required to achieve acceptable reliability. Care must be exercised in the evaluation of reliability problems, to determine the major cause of the outages, and to apply the most reasonable and cost effective solution.

7.7. Critical Limiting Factors

Critical limiting factors are components of the system or circuit that would represent general limits to available capacity on a significant portion of the system or circuit.

Examples of critical limiting factors include:

1. substation equipment
2. line regulators or reclosers
3. series step-up or step-down transformers
4. small-conductor line segments in an otherwise large-conductor line
5. subtransmission tap lines or line segments
6. switching equipment between parts of a system or circuit
7. cold load pickup

A short statement of such factors may be included with the planning study documentation to aid in a general understanding of the circuit or system. This may prevent spending a prohibitive amount of time regenerating study numbers or searching through a large system study file for a simple answer to each customer load addition question.

This statement could be done in the form of a succession of critical limiting factors, and the system upgrades needed to eliminate each. Such information might allow an engineer to give a timely and reasonably accurate answer to the repeatedly asked question, “How much load can be added to a given circuit area or system area?”

EXAMPLE: ENOCH CIRCUIT 12

CRITICAL LIMITING FACTORS

1. Mid-Valley Road line segment
   Length: 1/2 mile
   Conductor Size: #6 Copper
   Limitation Imposed:
   The rest of this line is 500 AAC conductor. Total area load beyond this segment is limited to 2.5 MVA, and total growth from present peak load is limited to 1.0 MVA. This segment also imposes a voltage drop of 0-4% on the rest of the circuit, depending on circuit loading.
2. Mid-Valley line regulators
   Capacity: 3.42 MVA
   Limitation:
   Area load beyond these regulators is limited to their capacity.
3. Enoch Substation transformer
   Capacity: 6.25 MVA
   Limitation:
   Capacity of transformer limits total loading on both circuits. If circuits continue historical growth patterns, circuit 12 can accommodate 4.0 MVA beyond existing peak.

7.8. Voltage Analysis

All distribution system studies require voltage analysis, which consider the following:

1. high and low voltage
2. tap zones or voltage spread
3. voltage balance
4. available voltage regulation
5. installed capacitors

Typically the voltage analysis will be done by a computer program such as FeederAll. When the analysis is done, voltage problems are identified per company standards, and solutions are compared on an economic basis.

In order to meet company standards during normal operation, the FeederAll model should typically have the node low voltage limit set at .97 p.u. and the node high voltage limit set at 1.04 p.u. In areas where tapped transformers are used, the node low voltage limit can be set to .95 p.u.

The voltage is modeled on the primary system, and is the annual high and low for all of the locations in the area. The area should be modeled under at least three loading conditions:

summer peak, winter peak, and annual light loading. These voltages are compared to levels given in the Engineering Handbook, sections 1B.3 (), 1C.2.1 (), and 1.C.2.2 (). The base for both voltage level standards is the ANSI range A voltages. At the customer's point of delivery, each phase should be checked separately for compliance to ANSI range A for the annual high and low voltage conditions expected over a year's operation of the system.

Voltage balance is covered in the Engineering Handbook section 1C.3.1, Voltage Balance. A primary voltage unbalance of more than 3% should be considered for correction. When voltage unbalance is present, the lowest and highest measured phase voltages are to be considered when comparing to the ANSI range A table.

Voltage regulators are normally included in the feeder model. Some programs such as FeederAll can include regulator settings to model the effect of a line drop compensator more accurately. In some cases the model may have to restrict the range of regulation in order to accommodate an overloaded regulator.

Capacitors are included as switched or fixed in the feeder model. Typically, the switched capacitor is modeled as on during the peak load, and off during light load. Some switched banks may need to be modeled as fixed banks if they are normally on during light load.

Sections 7.8.1 through 7.8.4 below discuss voltage problems that can occur on a primary system and have more than one solution.

7.8.1. High Voltage

When high voltage problems occur, evaluate the following items:

1. Check the utilization transformer taps.
2. Check the regulator base voltage. Sometimes the base voltage can drift due to a contaminated control potentiometer or other control malfunctions.
3. Check the R and X settings of the compensation.
4. Leading power factor during light load can result in high voltage.
5. Large amounts of lightly loaded underground cable can cause high voltage.
6. Changing the tap settings of substation transformers can help reduce high voltage and can help the substation regulator or LTC maintain appropriate range.

7.8.2. Low Voltage

When low voltage problems occur, evaluate the following items:

1. Unbalanced load or a source voltage unbalance can result in lower than expected voltage. Balancing load can help balance voltage on the feeder and possibly help balance the source. The use of single-phase regulators in the substation can help balance voltage from an unbalanced source.
2. Check power factor and add capacitors. There is a recommended level for power factor shown in the Engineering Handbook, Section 1B.3, Planning Standards for Voltage.

3. Add line regulators. This costs more than capacitors, but will raise the voltage higher, can help balance the voltage on a three-phase line, and adjusts voltage automatically.
4. Adding more phases and splitting up the load can help with voltage balance and raise the voltage level.
5. Reconductoring sections of line can help raise the voltage and possibly improve voltage balance, especially if the existing line is built with different conductor sizes. Some lines in the past were built with a greatly reduced neutral, which can cause operating problems such as stray voltage.
6. If there are series transformers on the feeder, they should be checked for loading. Even if the transformers are not overloaded, increasing the size of the bank can help reduce the voltage drop. Changing the tap setting on the transformer can raise the voltage.

7.8.3. Voltage Balance

When voltage imbalance occurs, evaluate the following items:

1. Balance load first. Occasionally the source is unbalanced and single-phase regulators can be added depending on the load involved.
2. Check for unequal phase wires.
3. Check current on each leg of a capacitor bank to be sure that all phases really are energized.
4. Check connections on the feeder. Bad splices, tap connectors, washers under the fuse head, or blown fuses can cause voltage and current unbalance.

7.8.4. Voltage Spread

Voltage spread is defined as the percentage difference between the highest voltage and the lowest voltage that the customer sees in a defined period of time. It is usually thought of as the difference between the lowest voltage encountered during the calendar year, and the highest voltage encountered during the calendar year, and is expressed as a percentage by dividing the difference in voltage by the nominal voltage. For a customer located close to the substation, the highest voltage encountered will be when the substation LTC or regulator cranks up the voltage during the peak load, and for a customer located at the remote end of a rural feeder, the highest voltage would occur during light load conditions. The lowest voltage seen by the close-in customer would usually occur at light load, and for the remote customer the lowest voltage will usually occur at peak load.

Currently, the State of Washington UTC requires that, “The variation in voltage shall not be more than five percent above or below the standard voltage adopted,” and total voltage variation “shall not exceed eight percent.” All other state regulatory agencies merely require keeping within plus or minus five percent of nominal (ANSI range A). To keep the voltage at the metered point of delivery in ANSI range A usually means that the spread on the primary system should be kept below five percent.

If the distribution system is designed with voltage regulation at appropriate locations to achieve ANSI Range A on the primary delivery system, and the capability of the voltage regulation equipment to use compensation is used correctly, the voltage spread will usually be less than five percent. Problems with voltage spread usually occur on 15 kV distribution systems and are less frequent on 25 and 35 kV systems.

7.9. Protection Coordination

New projects or solutions as well as load growth projections should be checked against existing equipment or settings, or both, to ensure their adequacy. FeederAll, in conjunction with Aspen One-Liner, can be used for this purpose.

Balancing loads, adding phases, transferring loads, solving reliability problems, adding cooling systems to station transformers, etc. all can change the protection on a system. A more detailed protection coordination study may be necessary in some cases, but is not part of the planning study process.

7.10. Equipment Settings

Equipment settings should be checked periodically. Loading experienced by various pieces of equipment can vary due to load growth, load transfers, and voltage conversions. Equipment settings forms are available in the Relay Settings database or digital settings files. Settings of the following equipment should be checked regularly:

1. substation and line protective devices
   a. Compare pickup levels with peak load and available fault duty at the end of the protected section.
   b. Check breaker rating for continuous load and interrupting capacity.
   c. Check line fuse loadings against rating.
2. substation regulator or LTC or line regulator

   Check expected voltage output at peak load.
3. switched line capacitors

   Check settings on switched banks, especially when changing feed direction.
4. transformer tap settings

   substation

   distribution

7.11. Shunt Capacitors

Shunt capacitors on the distribution system provide power factor correction and voltage support.

7.11.1. Power Factor Correction

Power factor correction is beneficial to reduce losses and to reduce loading on transformers and conductors. Capacitors are installed near customers with high reactive demands or near substation transformers. Customers should be encouraged to install capacitors on their equipment to improve loading and voltage regulation on PacifiCorp's system. Capacitor switching is required where the reactive demand or voltage varies significantly during the day. FeederAll assists in the placement of capacitors. In rare cases, an excessive leading power factor may reduce fault interruption capability.

7.11.2. Voltage Support

A capacitor bank can be an economical means to raise voltage at the end of a feeder. Capacitor banks are installed at or beyond the point of low voltage. Three-phase capacitor banks are recommended. Capacitor switching is required when the voltage goes over guideline during light load.

7.11.3. Capacitor Bank Switching

The voltage swing during capacitor switching must fall within guidelines as given in Engineering Handbook sections 1B.3 *Planning Standards for Transmission Voltage* and 1C.5.1 *Voltage Fluctuation and Flicker*.

The voltage swing from capacitor switching is given by:

$$\text{Per Unit Voltage Swing} = (\text{Capacitor kvar})(X) / ((kV_{LL})^2(1000))$$

$$X = \text{Line reactance in ohms}$$

or

$$\text{Per Unit Voltage Swing} = (\text{Capacitor kvar})(X) / (100000 \text{ kVA})$$

$$X = \text{Line reactance in per unit @ 100 MVA Base}$$

7.11.4. Capacitors and Harmonics

Some capacitor bank locations provide a current path for harmonics injected into the distribution system. Harmonic currents can overheat the capacitor units and open the capacitor bank protective fusing. The preferred corrective action is to have the customer eliminate the harmonics injected into the distribution system. Other corrective actions may be taken on the distribution system, including detuning the harmonic resonant circuit or blocking the harmonic current path. The resonant harmonic path is detuned by changing the size or changing the location of the capacitor bank. The path of the harmonic currents is blocked by placing a reactor in the neutral of the capacitor bank.

8. Developing a Construction Plan

8.1. Solution Optimization

This section provides guidance on resolving common problems using acceptable engineering solutions. Other solutions not listed in this section may be a better choice. Also, consider solutions already recommended in adjacent study areas.

When evaluating an operating problem, the most cost-effective long-term approach is to solve it for the end year being studied. Solutions that relieve the problem for one or two years may only defer a longer-term solution.

To operate the distribution system in the most cost-effective manner possible, alternative solutions to problems must be considered and studied. Many problems may be solved by several different solutions or a combination of solutions. The easiest or most direct solution to a problem may not be the best or most economical one, or yield the best utilization of the system. Taking a system approach, as opposed to a circuit by circuit approach, usually produces better solutions. Be creative; sometimes "off the wall" ideas lead to very cost-effective and innovative solutions. The solution chosen for the plan should factor in engineering, operating, and economic aspects. Each proposed solution should identify the alternatives evaluated and the reasons for rejection.

8.1.1. Problem to Solution Index

Table 2 provides references to suggested solutions, organized by category and type of problem. The solutions to a given problem are not presented in preferential order. Other possible solutions may be available for a given problem that are not listed in the table. Frequently, a combination of solutions provides the best option.

Table 2—Problem Solution References

Issues \ Solutions	Build New Substation 1A	Replace or Add Substation Transformer 2A	Add Substation Cooling Equipment 2B	Parallel Substation Transformers 2C	Replace Overloaded Substation Equip. 3A	Increase Getaway Capacity 3B	Add Parallel Circuit Getaway 3C	New Feeder 4A	Transfer Load 4B	Reconductor 5A	Reconfigure System 5B	Add Underground Cable 5C	Remove an Environmental Hazard 5D	Replace Equipment 6A	Add Distribution Automation Equipment 6B	Replace Regulator 7A	Limit Regulator Operating Range 7B	Add Secondary Regulators 7C	Change Regulator Control Settings 7D	Add Line Regulator 7E	Relocate Line Regulator 7F	Install Line Capacitors 8A	Install Capacitor Switches and Controls 8B	Replace Step-Up or Step-Down Transformers 9A	Change Utilization Transformer Taps 9B	Voltage Conversion 9C	Add Protective Device 10A	Replace Protection Equipment 10B	Relocate Protection Equipment 10C	Demand Side Management 11A
Substation																														
Transformer	X	X	X	X				X	X						X											X				X
Regulator		X		X				X	X						X	X	X									X				X
Transformer Protection	X		X					X	X						X											X				X
Paralleled Transformers	X	X	X					X	X						X											X				X
Bus Capacity	X	X			X			X	X						X											X				X
Circuit																														
Getaway						X	X	X	X						X											X				X
Circuit Protective Device					X			X	X																	X				X
Switches					X				X																					
Guide Line Loading Limit						X	X	X	X						X											X				
Line and Equipment																														
Overhead Conductor						X	X	X	X	X					X											X				X
Underground Conductor								X	X	X		X			X											X				X
Line Switch									X					X												X				
Switch Cabinet or Device									X					X																
Regulator									X					X	X	X					X			X		X				
Protective Device																														
Recloser									X					X												X		X	X	
Fuse									X					X													X	X	X	
Series Transformer																														
Step Up or Down	X							X	X						X									X		X				X
Isolation Bank	X																							X		X				X
Grounding Bank Fault Capacity	X							X	X															X		X				
Service Quality Problems																														
Steady State Voltage Levels		X		X				X	X	X					X			X	X	X		X	X	X	X	X				
Regulator Range								X	X	X					X					X	X	X	X	X	X	X				
Regulator Settings															X	X			X											
Capacitor Controls															X	X			X		X		X	X		X				

Issues \ Solutions	Build New Substation 1A	Replace or Add Substation Transformer 2A	Add Substation Cooling Equipment 2B	Parallel Substation Transformers 2C	Replace Overloaded Substation Equip. 3A	Increase Getaway Capacity 3B	Add Parallel Circuit Getaway 3C	New Feeder 4A	Transfer Load 4B	Reconductor 5A	Reconfigure System 5B	Add Underground Cable 5C	Remove an Environmental Hazard 5D	Replace Equipment 6A	Add Distribution Automation Equipment 6B	Replace Regulator 7A	Limit Regulator Operating Range 7B	Add Secondary Regulators 7C	Change Regulator Control Settings 7D	Add Line Regulator 7E	Relocate Line Regulator 7F	Install Line Capacitors 8A	Install Capacitor Switches and Controls 8B	Replace Step-Up or Step-Down Transformers 9A	Change Utilization Transformer Taps 9B	Voltage Conversion 9C	Add Protective Device 10A	Replace Protection Equipment 10B	Relocate Protection Equipment 10C	Demand Side Management 11A
Transient Voltage Levels																														
Motor Starts								X	X	X						X			X			X	X	X		X				
Capacitor Switching								X	X	X						X								X		X				
Harmonics								X	X	X		X				X								X		X				
Reliability Problems																														
Frequent Outages	X	X					X	X	X	X	X	X	X	X	X												X	X	X	
Excessive Risk or Exposure		X			X	X	X	X	X	X	X	X		X													X	X	X	
System and Economic Problems																														
VAR Delivery Limitations (Power Factor)									X						X							X	X							
Economic Performance (Efficiency)	X							X	X	X			X	X	X					X	X	X	X	X		X				
Capacity Utilization			X	X			X	X	X	X	X		X	X	X	X				X	X	X	X	X	X	X	X	X	X	

8.1.2. Common Solutions

The following are common solutions to various problems. More creative solutions may exist for many of these problems. This list is not intended as a limit to the solutions.

1.A) New Substation

Build a new substation and corresponding circuits. The size and placement of such a substation must be considered carefully. Many factors are involved, including:

1. location of load growth
2. level of land development
3. location and capacity of subtransmission lines
4. available land for siting a substation and corresponding transmission and distribution lines
5. political issues such as "not in my back yard" (or "view")
6. site accessibility

7. load growth rates in the area
8. distribution system voltage

Siting and sizing a new substation must be done in close collaboration with the Area Planning study effort. Both studies must reflect the need and consequences of an additional substation. Also, siting a substation is best done many years in advance, considering possible political impediments to its construction.

2.A) Replace or Add a Substation Transformer

Replace an existing substation transformer with a larger one. Note that unless the substation was designed for the larger transformer, many other substation components may also have to be upgraded. Selection of the transformer size must be done in close collaboration with the Area Planning study effort, which will include analysis of other substation and subtransmission components. Both studies must reflect the need and consequences of a larger substation transformer. Also, be sure the added substation capacity may be fully utilized at that location as the surrounding area becomes more developed. Even with getaway upgrades, line upgrades and additional circuits, the topology of the surrounding distribution system may not permit the added capacity to be utilized fully. Other factors to consider include the ability to take the new transformer out of service for maintenance, which may be limited by the capacity of available mobile transformers.

Install an additional substation transformer somewhere in the system and transfer load to it. This may be at the substation where the transformer is expected to be overloaded, but it is not a requirement. Often, the best location for additional capacity is in a substation located where the load is likely to grow in the future, or where existing circuit capacity exists to relieve the expected overload condition. Additional circuits are usually required to utilize the added transformer capacity.

Selection of the transformer size and location must be done in close collaboration with the Area Planning study effort, which will include analysis of other substation and subtransmission components. Both studies must reflect the need and consequences of a new substation transformer.

2.B) Add Substation Transformer Cooling Equipment

Add fans or oil pumps and coolers to an existing transformer. Some transformers were designed to accept additional cooling equipment, but were not purchased with it. Other transformers may be able to accept additional retrofit cooling equipment. There may be adverse consequences to this action, however, such as transformer protection complications or environmental issues, that must be considered. Selection of this solution must be done in close collaboration with the Area Planning study effort, which will include analysis of other substation and subtransmission components. Both studies must reflect the need and consequences of increased substation transformer loading.

2.C) Parallel Substation Transformers

Where two matched transformers exist in the same substation, and the other transformer is not overloaded, parallel the transformers. This will require using a bus tie breaker and interconnecting the regulator or LTC controls. The transmission side of both paralleled transformers must be fed from the same bus. This solution should be cleared with Area Planning, since there may be adverse consequences from the transmission perspective. In addition, system power quality may suffer due to increased line exposure. Also, check the protection coordination for the distribution circuits to verify proper device operation and fault duty under both separate and parallel transformer operation.

3.A) Replace Overloaded Substation Equipment

Replace overloaded equipment where it is not capable of supplying the full rating of the corresponding transformer or circuit as prescribed in the planning standards. Equipment in this category could include switches, metering or protection transformers, bus work, circuit breakers, and reclosers. Solutions in this category should be coordinated with Area Planning.

3.B) Increase Getaway Capacity

Replace the circuit getaway conductors. This is applicable for both overhead and underground getaways. Replacement of overhead getaways may involve tension limitations on the substation steel, clearance and guying issues, or pole replacement. Replacement of underground getaways may involve replacement of undersized conduit or ordering of special copper cable.

3.C) Add Parallel Circuit Getaway

Install a second set of underground getaway conductors in parallel with the existing getaway. This may involve installing a second conduit or using a spare conduit run. Special termination equipment may be required at either end of the parallel runs. This solution may be less expensive than replacing the existing getaway, and provides the additional benefit of partial backup.

4.A) New Feeder

Construct a new circuit from a substation with transformer capacity within the distribution system and transfer load to it. Where most components in a system are operating near planned capacity, this may be the most practical solution. Check for situations where the added load causes unexpected problems, such as low voltage, or subtransmission operating problems. Also check the distribution protection coordination for the new configuration. Often, multiple load transfers will be required to move load from where the problem exists to where the new capacity is added. A new circuit may also be used to isolate a critical customer from lines exposed to hazards.

4.B) Transfer Load

Transfer load to circuits fed from other substations or circuits where excess circuit and substation equipment capacities exist. Check for situations where the added load causes unexpected problems, such as low voltage, or subtransmission operating problems. Check the distribution protection coordination for the new configuration, and verify that the added load does not cause unexpected problems on another circuit, such as low voltage or reduced reliability problems. Often, multiple load transfers will be required to move load from where the overload or operating problem exists, to where the capacity exists. Sometimes additional circuit work or a new circuit is required to facilitate the necessary load transfers.

5.A) Replace Primary Overhead Conductor (Reconductor)

Primary circuit conductor ampacities are limited by operating temperature. The standard limits are based on conservative operating conditions, limited to a maximum temperature of 176_F for aluminum conductors and 212_F for copper. Ambient conditions that significantly deviate from the standard operating conditions can increase or decrease the load capacity of the conductor. Clearances based on a 140_F conductor operating temperature may further reduce the line's capacity. Connectors in poor condition may also restrict the capacity of the primary conductors.

Replace an overloaded conductor or a small conductor where excessive voltage drop occurs, with a larger conductor. Where voltage correction drives the reconductoring, the length of line to be reconductored depends on the amount of voltage correction necessary and the size of the replacement conductor. Reconductoring may involve significant reconstruction of the pole line including replacement, and in some cases relocation, of many of the poles. Costs for reconductoring often are much higher than for constructing a new pole line. When selecting a new conductor, use the economic conductor size, not the minimum size to carry the load. Once the work is required, the lowest total ownership cost for the new line should be the important factor, not the lowest first cost.

Where a regulator has run out of range or becomes overloaded, one option is to reconductor part of the line ahead of the line regulator to improve operating voltage and relocate the regulator bank further out on the circuit. This action may be consistent with the needs for the system as a result of load growth.

5.B) Reconfigure System

Change the line route or system configuration to avoid hazards such as trees, animals, vehicles, etc. This may also improve access to protective devices, thus reducing outage time.

5.C) Add Underground Cable

Replacing existing underground cable with larger cable is usually not economical. Install additional underground cable and reconfigure the underground system to relieve an underground overload condition, or provide an alternate feed to transfer load. This may involve construction of a backbone circuit or installation of a new primary dip to split the system up. Significant conduit installation and trenching may be involved. This may not be desirable, or possible, in established areas. Also, underground systems are usually designed with redundancy; looped systems are encouraged for reliability, but are not always practical. If an underground cable is overloaded, a review of the system topology may be needed.

5.D) Remove Environmental Hazards

Remove an environmental hazard by such actions as trimming trees along the line route or installing guy guards. Wildlife protection equipment may be used to improve reliability where birds or rodents tend to cause outages.

6.A) Replace Equipment

Replace overloaded, unreliable or deteriorated equipment. This could include any distribution equipment or pole line hardware that results in capacity limitations or frequent outages. Replacement of troublesome equipment may be more cost effective than other alternatives. Situations where equipment conditions or load limitations prevent other economical solutions are usually best solved by replacing the limiting equipment.

6.B) Add Distribution Automation Equipment

Add dispatcher-controlled equipment, such as radio-controlled line switches. This may reduce outage time or prevent blackouts during peak loading.

In some cases, voltage or loading problems may be solved economically by installing load control devices. Where large industrial customers are involved, a special reduction in rates may be enough incentive to accept load shedding on peak or modify usage patterns to reduce load when the utility requests the action.

7.A) Replace Regulator

Where a separate substation regulator is used and overloaded, replace it with one matching or exceeding the capacity of the substation transformer. New line drop compensator settings will be required.

Where line regulators are overloaded, replace them with a larger bank. This will require new regulator control settings. Refer to the Field Engineering web page for regulator control setting instructions. New poles, racks and line hardware may be required for the added weight and load.

7.B) Limit Regulator Operating Range

Where the full regulator operating range is not required to maintain voltage, limit the amount of boost or buck. Regulators, like transformers, are generally limited by thermal capacity. By restricting the amount of boost or buck, less heat is generated within the regulator, enabling it to carry more load. Regulators are also limited by the current rating of their contacts, so not all regulators gain capacity with restricted range. Also check that the full range of the regulator is not required for outage conditions on the subtransmission system.

7.C) Add Secondary Regulators

Where only a few remote customers are involved, install secondary regulators. Because they are low-voltage devices, a few secondary regulators may be more economical than correcting a primary voltage problem.

7.D) Change Regulator Control Settings

Optimize the line drop compensator settings on existing regulators. To maintain ANSI range A voltage to customers, the regulator is usually set to output 1.0 p.u. (120 V) at no load, and a maximum of 1.05 p.u. (126 V) at peak load. The full load settings should allow for some load growth, and for the voltage bandwidth of the regulator control. A peak load setting yielding 1.045 p.u. (125.5 V) at peak is considered prudent. Reactive (X) compensation should be applied carefully where switched capacitors or customers with high reactive loads are involved. Where settings needed to provide full voltage boost at peak load could result in excessive voltage under unusual load conditions, the use of a first house protector control to limit the maximum output voltage is recommended. Refer to the Field Engineering web page for regulator control setting instructions.

7.E) Add Line Regulator

Add a line regulator to an existing line to boost or buck voltage. This will also improve voltage spread when the voltage range is too wide. Add line regulators ahead of where a voltage problem begins. Allow room for load growth in the placement and sizing of the regulators. Where transformer taps have been used to correct sagging primary voltage, the taps beyond the regulator must be changed to avoid delivering high voltage to customers. This O&M expense needs to be included in the cost of the regulator installation. Line drop compensator settings should be optimized, and should allow for some load growth.

When adding a line regulator, existing line regulators on the feeder may have to be repositioned. The usual limit is three line regulators in series, including the substation regulator. Each successive regulator needs an increasing amount of time delay to avoid excessive tap changing. Where more than three series regulators are required for voltage correction, other alternatives should be attempted first. Refer to capacitors, utilization transformer tap settings, reconductoring and voltage conversion.

Where an open delta regulator bank is running out of regulation range, a third regulator may be installed to increase the total boost to 15%.

7.F) Relocation of a Line Regulator

Relocate a line regulator closer to the source to expand the regulated area, or farther out to correct excessive or inadequate regulation range. Usually, some additional voltage correction measure is used in conjunction with relocation of a regulator, such as reconductoring, load transfers, a new substation or circuit, or voltage conversion. When relocating a regulator, be sure that capacity and regulation range are adequate. The same general guidance applied for new regulators also applies to relocated regulators.

8.A) Install Line Capacitors

Add capacitor banks to the circuit to improve voltage, to supply vars locally for low power factor loads, or to improve the power factor of the circuit beyond an overloaded line section. The FeederAll capacitor optimization may provide a good starting point. Switches and controls for the capacitor banks may be required, if the added capacitors cause high voltage under light load conditions. Voltage or current controls usually work best. Var controls work well when large var consumption correlates with voltage problems. Time and temperature controls seldom work well. Capacitor controls need periodic inspection and maintenance. These costs need to be figured into the economic analysis used to compare alternatives.

8.B) Install Capacitor Switches and Controls

Where capacitors cause excessive leading power factor or high voltage under light load conditions, install capacitor switches and controls. Selection of the control type depends on the circuit conditions at the location of the control. Voltage controls usually work best where line voltage varies enough to trigger the capacitor switching, and the capacitor does not cause excessive voltage change. Current controls work well where variation in line current correlates with the need for the capacitor. Var controls work well when large var consumption beyond the capacitor correlates with the need for the capacitor. Time and temperature controls seldom work well. Capacitor controls need periodic inspection and maintenance.

9.A) Replace Step-Up or Step-Down Transformers

Replace an overloaded step-up or step-down transformer with a larger one. Check the protection coordination of the device used to protect the new bank with up-stream and down-stream devices.

Where excessive voltage drop occurs through a step-up or step-down transformer bank, replace the transformers with larger ones. Check the protection coordination of the device used to protect the new bank with up-stream and down-stream devices.

Replacing or adding to a transformer bank to change the configuration may be useful to improve voltage drop or to correct protection coordination problems. This may include converting a delta bank to wye or closing an open bank.

9.B) Change Utilization Transformer Taps

In areas where transformer taps are available on utilization transformers, change the tap settings to boost or buck the voltage to the customer. This establishes a tap zone with a different allowable voltage range. It is costly to create or change tap zones. Regulators or capacitors may be more economical. Be careful that the voltage does not go too high under light load conditions. Voltage drop problems are often associated with excessive voltage spread, which may require other corrective measures.

9.C) Voltage Conversion

Convert part or all of a circuit or system to a higher voltage and transfer it to another circuit. This is often practical where a higher-voltage distribution circuit is adjacent to the area experiencing a low voltage problem or overload condition. Check the protective device coordination of the circuit receiving the added load.

Where an overloaded step-down transformer is involved, convert part or all of the system beyond the overloaded transformer bank to the source-side voltage, and relocate the bank further out on the circuit or eliminate it.

Another practical application for voltage conversion, is to use a series step-up bank and corresponding down-stream voltage conversion to solve low voltage problems on long radial circuits. A new protection coordination study and new protective devices will be required.

Wholesale voltage conversion of a system involving new substations and circuits needs to be analyzed within the context of a long range plan, not just as a reaction to a low voltage problem.

Selection of this solution must be done in close collaboration with the Area Planning study effort, which will include analysis of other substation and subtransmission components. Both studies must reflect the need for, and consequences of, voltage conversion.

10.A) Add Protective Device

Add protective devices to reduce the number of customers affected by a line fault. Where a critical customer is served from lines exposed to hazards, installing a protective device such as a recloser may isolate the hazard from the customer. Outage times may be reduced with careful placement of protective devices when such placement improves fault locating. Automatic reset fault indicators may be installed to aid in the location of line faults.

10.B) Replace Protection Equipment

Replace the overloaded or overdutied protection equipment to gain more capacity. When doing this, a complete review of the protection coordination for the involved circuit is needed. Changing the equipment usually means higher settings that may not coordinate with upstream devices, and may not adequately protect the primary conductor and devices downstream from the new device.

Installation of higher-technology protective devices may prevent unnecessary outages. Microprocessor-controlled devices are available that can detect the difference between line faults and other disturbances that would result in a false trip with older devices. These devices may also be used to help locate a momentary fault condition by reporting the electrical conditions experienced during the fault.

10.C) Relocate Protection Equipment

Relocate overloaded or overdutied protective equipment further out on the circuit. A complete review of the protection coordination for the involved circuit will be required. Moving the equipment further out on the circuit usually means more line must be protected by the upstream device, requiring lower settings that may not work. This will also increase the area of exposure for the upstream device, and may reduce circuit reliability.

Outage times may be reduced by relocating protective devices so as to improve accessibility and to aid in locating faults.

11.A) Apply Demand-Side Management

Demand-side management involves applying measures to reduce the electrical demand and energy required by end consumers, while continuing to meet the consumers' expectations for end product usage, such as light and heat. Such measures may include improving building insulation, or installing high-efficiency lighting. Application of recent technology developments in motors and HVAC systems can yield substantial energy demand reductions while delivering satisfactory end results. Industrial consumers may be able to make improvements in their processes or equipment that reduce demand requirements and energy consumption. Other opportunities may exist with customer owned co-generation, or energy storage technologies.

8.2. Risk Assessment

In preparing a distribution system planning study, it is very important to discuss, preferably quantitatively, the relative risks of various decisions.

When determining risk for a proposed distribution construction item, just exceeding a guideline criterion does not automatically constitute high risk. The risk must be put in terms of its effect on customers and its potential cost. For example, many equipment overload situations are short in duration, and any associated equipment failures or service quality problems would affect only a relatively small number of customers. The risks associated with some proposed solutions could involve larger loads and larger revenues for longer periods of time. Other risks could be excessive emergency repair costs due to equipment cost or the use of customer-owned or other equipment. When identifying risk subjectively, put it in relative terms as compared to other potential risks.

The guideline planning criteria are generally conservative. They are intended to flag a problem before it becomes serious. In many situations, for example, equipment may be safely utilized well above the guideline rating. This makes an overload based on guideline a low-risk proposition. In some cases, however, the guideline rating may be very close to the capability of the equipment, due to extreme environmental conditions. Both situations must be explained in the study.

It is imprtant to quantify the risk of not doing a proposed construction item. Try to answer the following:

1. How many hours per year is the risk present?
2. How many customers would be affected?
3. How much load would be affected?
4. How much revenue would be lost?
5. How much would emergency repairs cost?
6. How long would it take to perform emergency repairs, if at all possible?
7. What is the likelihood that a failure or service quality problem would occur?

8.3. Economic Justification

An economic analysis must be performed on the proposed solutions. Even though some solutions may not have any alternatives, the business aspects must be addressed. Economic analysis may include the information shown in sections 8.3.1 through 8.3.3 below. Select the best combined economic and engineering solution.

8.3.1. Total Costs

Total costs are equipment, labor and overhead costs of the project in current year dollars.

8.3.2. Indirect Costs or Benefits

Indirect costs or benefits are difficult to put into dollar values, but should be included for consideration. Examples of indirect costs or benefits include political ramifications,

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sensitive or strategic customers, system benefits (costs) above and beyond what the solution may immediately fix, short-term outlook and long-term outlook.

8.3.3. T&D Economic Model

The T&D Economic Model program was developed to evaluate economic viability. This program can be found on the Power Drive. Inputs include total construction costs, year of construction, demand loss savings and energy losses.

The energy loss calculation in FeederAll may not model all situations accurately. A feeder with mostly industrial load will have a higher load factor and loss factor, while a feeder serving a resort area with large seasonal load variances will have lower load and loss factors. In these cases, the load factor, loss factor and energy losses shall be calculated for the specfic feeder, using the following equations:

$$LF = \frac{\left[\frac{\text{Total Annual Energy}}{8760}\right]}{\text{Annual Peak Value}} \qquad \text{Eq (2)}$$

$$lf = .3 * (LF) + 7 * (LF)^2 \qquad \text{Eq (3)}$$

LF=load factor

$$\text{Annual Energy Loss} = \text{Loss Factor} * \text{Demand Loss} * 8760 \qquad \text{Eq (4)}$$

Complex projects that involve variables out of the scope of the model (e.g., multiple capital in service dates, salvage after the in service date, etc.) should be forwarded to Financial Analysis. Other conditions on a case-by-case basis may warrant custom modeling of a project's economics. If in doubt, call Financial Analysis.

8.4. Contingency Plan

Contingency planning is not a required element in a planning study, but the engineer may determine that a contingency plan is a useful addition to the study.

8.4.1. Substation

The transformer loss contingency procedure examines the loss of a substation and recommends a restoration scheme to be used in such an event. The purpose of these procedures is to minimize customer outage times without overloading the distribution system. Both summer and winter ratings should be analyzed. Substations with paralleled transformers have the potential to lose or damage both transformers or LTCs.

In the event of major substation equipment failure, recovery methods as discussed below in Sections 8.4.1.1 through 8.4.1.3 should be detailed in the contingency plan, individually or in combination.

8.4.1.1. Mobile Transformers and System Spare Equipment

List the equipment number, rating, location, and restoration time. Restoration time will depend on whether the equipment is mobile (ready to roll) or spare (may need time to make transportable), whether the station is "mobile ready," and whether travel will be affected by weather conditions. Obtain or verify the information with the Area Planner.

8.4.1.2. Load Transfers

Determine whether load transfers can be done using emergency substation and feeder ratings. Check for abnormally low voltages at the ends of feeders. Settings of feeder relays and substation LTCs or regulators should be reviewed when transformers are loaded higher than normal, since inadequate feeder protection or excessive compensation may occur.

8.4.1.3. Partial Load Restoration

If mobile transformers are not available, and if load transfers cannot be accomplished to restore customers completely, detail a list of load to pickup or shed, and the estimated outage time.

8.4.2. Major Feeder

Ordinarily, feeder contingency plans will follow the same rules as those for substation contingency plans (listed above). A list showing mainline jumper points, cutout fuse or solid blade locations and switches should be included in the contingency plan.

8.5. Study Cycle Class

Study class determines how often a study should be completed to provide valid supporting documentation to the budget forecast. There are two valid schools of thought when determining study class:

1. The first method to determine study class depends on the following three questions:

   How accurate are the projected loads? (confidence in load forecast)

   How fast is the area growing? (load growth)

   What reliability changes have taken place with circuits within the study? (network initiatives)

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Determine the study class using the flow chart in Figure 2.

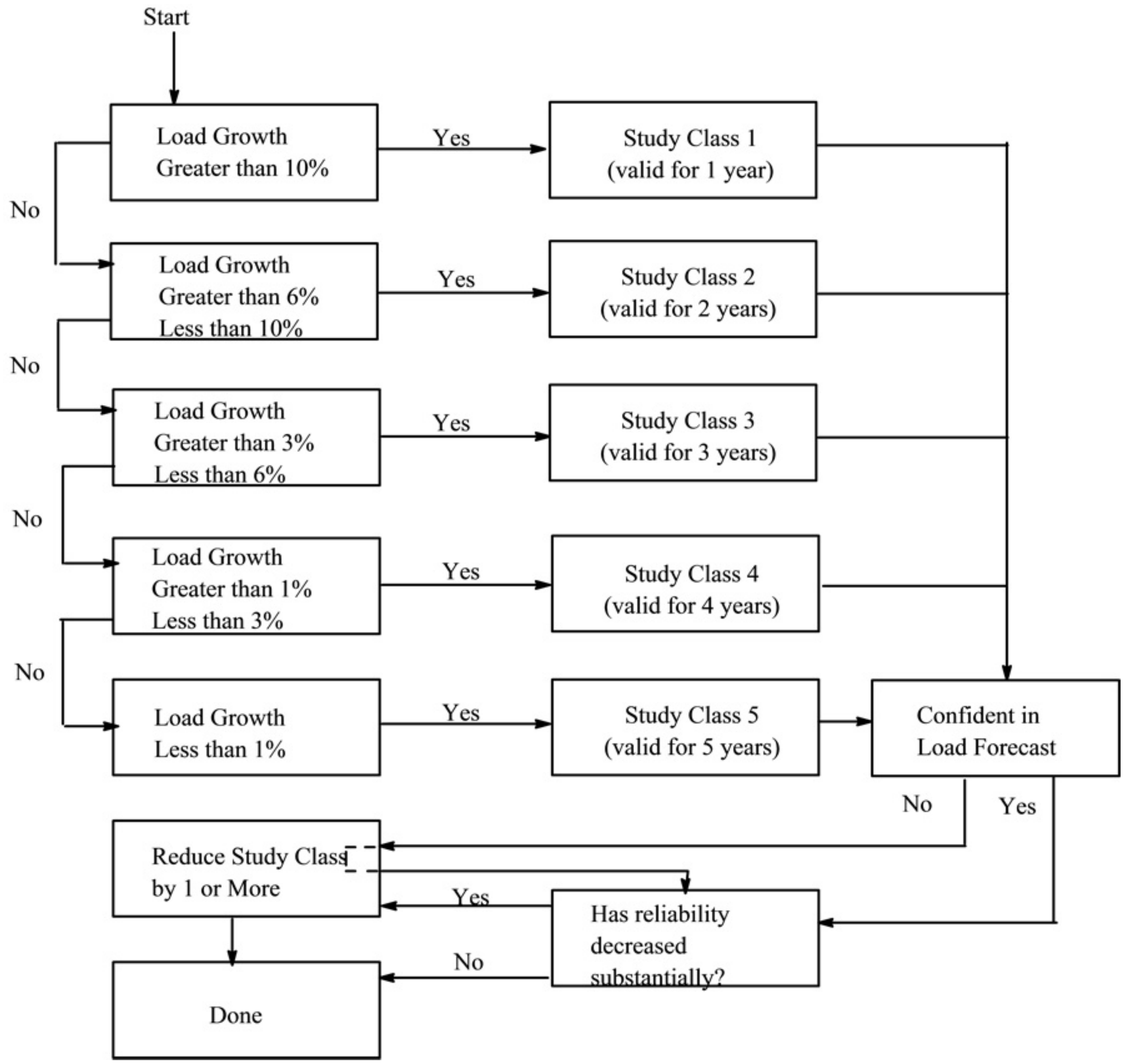

Figure 2—Study Cycle Class Flowchart

2. The second method to determine study class depends on the following five questions:

   How fast is the area growing? (load growth)

   Is any equipment currently overloaded? (overload)

   Are reliability issues involved? (network initiatives)

   Are expensive projects involved? (economics)

   Are long lead times involved? (budget)

Determine the study class using the flow chart in Figure 3.

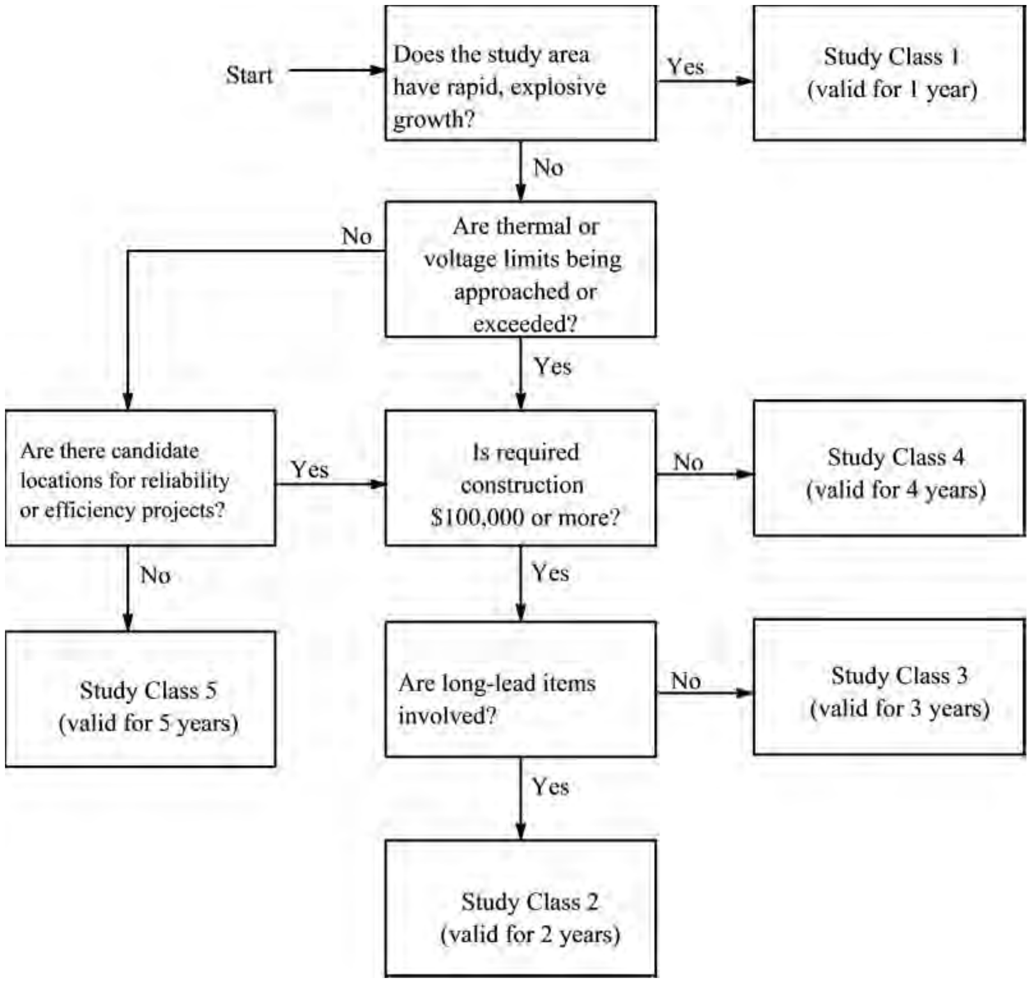

Figure 3—Study Cycle Class Flowchart

9. Creation of Distribution System Planning Study Report

9.1. Report Preface

This section covers the required parts of the distribution study report. The report's main purpose is to present a concise summary of the study parameters, data, potential problems, and solutions in a standard format. This will give management a clear picture of the reasons for budget projects, and a means of prioritizing them. It also provides the engineer with a tool for responding knowledgeably and prompty to new service requests, large scale operational problems and budget situations.

The report consists of:

Construction Plan and Approval
Study Summary
Load Forecast for each substation and circuit in the study
P&N for each proposed budget item
Map(s) showing the study area and proposed budget items

Templates for the ‘Construction Plan and Approval’ and the ‘Study Summary’ are available on the Power Drive, and can be expanded or contracted to fit the needs of each study and plan. If a certain section or sections of the summaries do not apply to a particular area plan, label them “not applicable” to indicate that these “standard” concerns have been given appropriate consideration.

Brevity will make the report much more useful, and is strongly encouraged. Detailed supporting documentation, as explained in the rest of the DSPSG document, can be attached to the back of the report and should be customized as needed for the particular area plan.

9.2. Construction Plan and Approval

This sample form has been developed to provide certain necessary information in a uniform manner, and to serve as a document of approval. A blank Excel sample can be found on the Power Drive.

STUDY TITLE

INCLUDED SUBSTATIONS AND CIRCUITS

Substation/Area Name(s)	Ckt. #(s)	Ckt. Voltage(s)
____________	____________	____________
____________	____________	____________
____________	____________	____________
____________	____________	____________
____________	____________	____________
____________	____________	____________

Item	Description of Work Required	Construction Cost Estimates In 1999 dollars, 1000s, Total			
		2000	2001	2002	2003
	Total:				

District: ______________________________

Prepared by: ______________________________ Date: ____________________
Title

Reviewed by: ______________________________ Date: ____________________
Area Engineer

Reviewed by: ______________________________ Date: ____________________
Area Planning Engineer

Approved by: ______________________________ Date: ____________________
Field Engineering Manager

Approved by: ______________________________ Date: ____________________
Operations Director/Manager

9.2.1. Study Title

The title should be brief but sufficiently descriptive to avoid confusion with subsequent studies of other parts of the same system.

9.2.2. Substations, Circuits, Voltages

List the substations and associated circuits and voltages involved in the study.

9.2.3. Date Completed

This is the date the study was completed and ready for review.

9.2.4. Construction Requirements Forecast

Under the heading "Description of Work Required," list individually each major item of a given year's program, and show the estimated cost in the proper year column to the right. Show the total construction cost for the multiyear study at the bottom. Remember to change the year the dollars are being given in at the top right of the work sheet.

9.2.5. Prepared By

This is the individual who prepared the study.

9.2.6. Reviewed By

These spaces are for the review signatures of the area engineer and area planner.

9.2.7. Approval Section

Approvals for distribution plans include:

Engineering Manager
Operations Manager

Informational copies may also need to be reviewed by or sent to:

AVP

9.3. Study Summary

STUDY PARAMETERS

__________ STUDY BASE YEAR (Year that load projections begin)

__________ STUDY END YEAR

FORECASTED AREA LOAD GROWTH

Location	% Growth/yr

SUMMARY OF ECONOMIC AND OTHER FACTORS AFFECTING AREA LOAD GROWTH:

Other Comments:

PROBLEM AREA SUMMARIES

SIGNIFICANT LOADING PROBLEMS SUMMARY

#	Location	Year	%Grwt	%Overload	Description
•					
•					
•					

SIGNIFICANT VOLTAGE PROBLEMS SUMMARY

#	Location	Year	Voltage (p.u.)	Description
•				
•				
•				

SIGNIFICANT RELIABILITY PROBLEM AREAS SUMMARY

#	Location	Years	CPI	# Outages	# Mom.	# Cust	Years	Customer Dissatisfaction
•								
•								
•								

SIGNIFICANT OTHER PROBLEMS SUMMARY (LOSSES, POWER FACTOR, ETC.)

#	Location	Year	Description
•			
•			
•			

SOLUTIONS SUMMARY

Problem Description ____
Solution Project Name: ______________________________ Year: _______ Cost: _______
Cost/Benefit Ratio: __________________
Brief Description (include any risk):

Alternate Project Name: ______________________________ Year: _______ Cost: _______
Cost/Benefit Ratio: __________________ Bucket: _______________ Category: ____________
Brief Description and Reason why Not Used (include risk):

Alternate Project Name: ______________________________ Year: _______ Cost: _______
Cost/Benefit Ratio: __________________
Brief Description and Reasons why Not Used (include risk):

-
-
-

Problem Description ____
Solution Project Name: ______________________________ Year: _______ Cost: _______
Cost/Benefit Ratio: __________________
Brief Description (include any risk):

Alternate Project Name: ______________________________ Year: _______ Cost: _______
Cost/Benefit Ratio: __________________ Bucket: _______________ Category: ____________
Brief Description and Reason why Not Used (include risk):

Alternate Project Name: ______________________________ Year: _______ Cost: _______
Cost/Benefit Ratio: __________________
Brief Description and Reasons why Not Used (include risk):

CONTINGENCY STUDIES SUMMARY

Location Description

-
-
-

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10. Computer Resource Reference

Contact Field Engineering Support for current computer resource references.

Table 3—Computer Resources

File Name	File Format	Description
CPA.xls	Excel	CPA - Construction Plan and Approval. This document is required in the distribution plan report.
studysum.doc	Word WordPerfect	Study Summary - This document is required in the distribution plan report. It is a synopsis of the system studies, the major operating problems and proposed solutions.
CPA.doc	Word	This document has instructions for the CPA.xls spreadsheet
checklst.doc	Word	Checklist for distribution system planning
ampacity.xls	Excel	Conductor ampacity calculations. This spreadsheet allows calculation of conductor ampacity for given ambient conditions and line location.
ampacity.doc	Word	Conductor ampacity instructions. This document discusses the effects on conductor ampacity of different conductor and ambient conditions. Use with ampacity.xls.
t&dyy.xls	Excel	Corporate Financial Model - yy = year

11. Issuing Department

The Engineering and Asset Management Documentation department of PacifiCorp published this document. Questions regarding editing, revision history and document output may be directed to the lead editor at eampub@pacificorp.com. Technical questions and comments may be directed to standards engineering.

This material specification shall be used and duplicated only in support of PacifiCorp projects.

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 2, 2021

Ken Kaufmann
Ken@kaufmann.law

RE: OR UM 2118
Sunthurst 13th Set Data Request (1-4)

Please find enclosed PacifiCorp's Responses to Sunthurst 13th Set Data Requests 13.1-13.3. The response to Sunthurst 13.4 will be provided separately.

If you have any questions, please call me at 503-813-5934.

Sincerely,

____/s/___
Cathie Allen
Manager, Regulatory Affairs

UM 2118 / PacifiCorp
March 2, 2021
Sunthurst Data Request 13.1

Sunthurst Data Request 13.1

Please refer to PacifiCorp's DR3.4. Did each of the following persons attend the June 9, 2020 meeting between PacifiCorp and Sunthurst regarding Q1045 interconnection?

(a) Dean Miller
(b) Kris Bremer
(c) Adam Lint
(d) John Mark
(e) Dirk Frailey
(f) Milt Patzkowski
(g) Adam Lu
(h) Matt Loftus, Senior Transmission Counsel
(i) Graham Retzlaff
(j) Scott Beyer

Response to Sunthurst Data Request 13.1

(a) Dean Miller - Yes
(b) Kris Bremer - Yes
(c) Adam Lint - Yes
(d) John Mark - No
(e) Dirk Frailey - Yes
(f) Milt Patzkowski - No
(g) Adam Lu – PacifiCorp does not know this name so believes the answer is no.
(h) Matt Loftus, Senior Transmission Counsel - Yes
(i) Graham Retzlaff - Yes
(j) Scott Beyer - Yes

Respondent(s): Kris Bremer

UM 2118 / PacifiCorp
March 2, 2021
Sunthurst Data Request 13.2

Sunthurst Data Request 13.2

Please provide all notes from the June 9, 2020 meeting from each of the above attendees, and any other PacifiCorp attendee at that meeting.

Response to Sunthurst Data Request 13.2

The Company assumes that the reference to "each of the above attendees" is intended to reference the attendees listed in Sunthurst Data Request 13.1. Based on the foregoing assumption, the Company responds as follows:

PacifiCorp has no meeting notes from this meeting.

Respondent(s): Kris Bremer

UM 2118 / PacifiCorp
March 2, 2021
Sunthurst Data Request 13.3

Sunthurst Data Request 13.3

Please complete the table in Sunthurst DR 8.13, columns (a) and (b), with non-confidential response.

Response to Sunthurst Data Request 13.3

Please refer to the table provided below:

Job (as reported in the Company's response to Sunthurst Data Request 5.1)	(a) Total Authorized Cost	(b) Total Amount Spent, to date	(c) Service Disruptions, if any
2017- replace control house wall air conditioner due to failure	$6,328	$16,690	none
2018 -west fence replace due to code violation	$30,242	$ 34,807	none
2019- replace battery bank and charger due to battery degradation	$26,512	$ 46,564	none
2019- replace three-phase regulator 542 due to failure in Sep 2018; replace transformer bank 1 arresters, install animal guarding, and replace bank #9 current transformer bank.	$153,151	$345,744	none
2019- replace regulator R816 controller due to failure.	$20,863	$6,157	None

Note: PacifiCorp believes the title for column (a) above would be more accurate if it were rephrased "Total initial authorized cost" as its possible, based on internal governance controls, that one or more of the projects would have to have been routed for approval for the increased spend above what was initially authorized.

Respondent(s): Kris Bremer

UM 2118 / PacifiCorp
March 9, 2021
Sunthurst Data Request 13.4 – 1st Revised

Sunthurst Data Request 13.4

Please refer to PAC/200, Patzkowski-Taylor-Vaz/36, lines 12-18. List all projects over $10 million subject to PacifiCorp's Capital Surcharge that were completed in 2019. For each project, list (a) the project cost, (b) the project Capital Surcharge, and (c) the project owner.

1st Revised Response to Sunthurst Data Request 13.4

The following revised response replaces the March 4, 2021 response in its entirety. The attachment has been revised.

Please refer to Confidential Attachment Sunthurst 13.4 1st Revised. Please note that, as described in PacifiCorp's response to Sunthurst Data Request 11.1, typically for turnkey projects, engineering, procurement, and construction are conducted by contractor(s) and not done by internal PacifiCorp personnel, which leads to a lower surcharge percentage being assigned to projects greater than $10 million.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

Respondent(s): Lori Holland, Scott Marchant

Confidential Attachment Sunthurst 13.4 1st Revised

REDACTED

Project Description	a.) Total 2019 Plant Placed in Service	b.) Surcharge	c.) Project Owner	Comment
Glenrock 1 Repowering	[redacted]	$122,540.05	PacifiCorp	Capped dollar amount from approved APR for entire Repowering project, excluding Foote Creek. Allocation by Wind facility done by asset accounting. Note not all Repowering projects went into service in 2019 so this is a partial list.
Glenrock 3 Repowering	[redacted]	$33,420.01	PacifiCorp	Capped dollar amount from approved APR for entire Repowering project, excluding Foote Creek. Allocation by Wind facility done by asset accounting. Note not all Repowering projects went into service in 2019 so this is a partial list.
Goodnoe Hills Repowering	[redacted]	$116,684.35	PacifiCorp	Capped dollar amount from approved APR for entire Repowering project, excluding Foote Creek. Allocation by Wind facility done by asset accounting. Note not all Repowering projects went into service in 2019 so this is a partial list.
High Plains Repowering	[redacted]	$122,540.05	PacifiCorp	Capped dollar amount from approved APR for entire Repowering project, excluding Foote Creek. Allocation by Wind facility done by asset accounting. Note not all Repowering projects went into service in 2019 so this is a partial list.
Leaning Juniper Repowering	[redacted]	$89,120.04	PacifiCorp	Capped dollar amount from approved APR for entire Repowering project, excluding Foote Creek. Allocation by Wind facility done by asset accounting. Note not all Repowering projects went into service in 2019 so this is a partial list.
McFadden Ridge Repowering	[redacted]	$33,420.01	PacifiCorp	Capped dollar amount from approved APR for entire Repowering project, excluding Foote Creek. Allocation by Wind facility done by asset accounting. Note not all Repowering projects went into service in 2019 so this is a partial list.
Rolling Hills Repowering	[redacted]	$89,120.04	PacifiCorp	Capped dollar amount from approved APR for entire Repowering project, excluding Foote Creek. Allocation by Wind facility done by asset accounting. Note not all Repowering projects went into service in 2019 so this is a partial list.
Seven Mile 1 Repowering	[redacted]	$133,680.05	PacifiCorp	Capped dollar amount from approved APR for entire Repowering project, excluding Foote Creek. Allocation by Wind facility done by asset accounting. Note not all Repowering projects went into service in 2019 so this is a partial list.
Seven Mile 2 Repowering	[redacted]	$33,420.01	PacifiCorp	Capped dollar amount from approved APR for entire Repowering project, excluding Foote Creek. Allocation by Wind facility done by asset accounting. Note not all Repowering projects went into service in 2019 so this is a partial list.
Total of 9 PacifiCorp Repowering projects, above:	**$707,225,536**	**$773,945**		
Energizing Customer Tools (ECT)	$14,581,733	$853,132	PacifiCorp	IT projects have their own surcharge rate. This specific project did not qualify as a capped project due it not being a turnkey, or EPC (Engineering, Procurement, Construction) project. IT surcharge rate ranged from 4.0% to 10.0% with an average of 8.0%.
Oregon New Large Load	[redacted]	$4,406,864	PacifiCorp	Capped surcharge rate project
Delta Fire Damaged Facilities	$36,173,835	$3,070,386	PacifiCorp	Project consolidated the replacement of assets due to the Delta Fire and did not qualify as a capped project due it not being a turnkey, or EPC (Engineering, Procurement, Construction) project. Standard rate applied ranging from 7.5-10.0% with 8.04% as the average rate.
Oregon AMI - IT System Modification	$32,187,669	$757,551	PacifiCorp	Capped surcharge rate project
NE Portland Trans Upgrade	[redacted]	$2,207,844	PacifiCorp	This specific project did not qualify as a capped project due it not being a turnkey, or EPC (Engineering, Procurement, Construction) project. Standard rate applied ranging from 7.5-10.0% with 8.04% as the average rate.
Sams Valley 500-230kV New Substation	$10,980,097	$677,285	PacifiCorp	Capped surcharge rate project
Wallula McNary 230kV Line	[redacted]	$1,323,268	PacifiCorp	Capped surcharge rate project
Total of 7 projects, above:	**$166,364,759**	**$13,296,331**		

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that, on the 11th day of March, 2021, I have caused to be served the foregoing *Sunthurst Energy, LLC's Exhibit List and Supplemental Exhibits (Sunthurst/500-501)* in OPUC Docket No. UM 2118 to those parties listed below by electronic mail at the address provided. Confidential (Sunthurst/501) material is being provided to qualified parties under Protective Order No. 20-363 via password-protected zip file.

DATED this 11th day of March 2021.

_/s/ Kenneth E Kaufmann
Kenneth E Kaufmann OSB 982672
Attorney for Sunthurst Energy, LLC

ADAM LOWNEY **(C)** MCDOWELL RACKNER & GIBSON PC	419 SW 11TH AVE, STE 400 PORTLAND OR 97205 adam@mrg-law.com