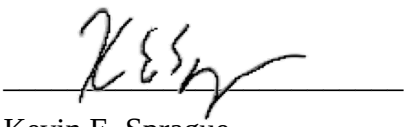
FOREWORD

The purpose of this document is to outline the distribution load projection process.

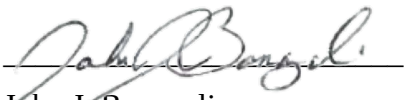
Any questions or inquiries regarding information provided in this document should be referred to the Manager, Distribution Engineering.



1/28/2022

Kevin E. Sprague
Vice President, Engineering

Date



Jan. 21, 2022

John J. Bonazoli
Manager, Distribution Engineering

Date

REVISION HISTORY

Revision #	Date	Description of Changes
0	05/22/2009	Initial Issue
1	08/22/2017	Revised to update procedure
2	08/01/2018	Updated section 4.1 paragraph 2
3	11/14/2019	Added paragraph regarding Unitil owned DG. All references to Director, Engineering updated to Vice President, Engineering. Revised Updating the Document (Section 1.3) to Responsibilities. Removed Request for Procedure/Change Form
4	7/6/2021	Added Minimum Daytime Load Forecasting. Updated for ten year forecasts and to include the incorporation of EV and DER.

5	1/20/2022	Revised to separate process when using actual minimum daytime loads or estimated minimum daytime loads based on peak loads in minimum daytime load forecasting.

Table of Contents

1.0 Introduction

1.1 Purpose

The intent of this document is to provide a guideline to assist Distribution Engineering personnel in the process of projecting the ten year distribution circuit and substation transformer load levels for use in planning system improvements in order to ensure the reliability of the electric system.

This guideline is not intended to be an all-inclusive, step-by-step procedure and should not replace sound engineering judgment.

1.2 Applicability

This document applies to the projection of load for distribution circuits operating at nominal primary voltages of 34.5kV or less and substation transformers operating at nominal primary voltages of 69kV or less.

This guideline does not apply to the projection of loads for the subtransmission systems and/or system supply transformers.

1.3 Responsibilities

This procedure is written and maintained by the Distribution Engineering Department to whom any questions relating to its content or application should be addressed.

1.4 Availability

Current copies of this procedure can be found on the Engineering Department Only Drive. Hard copies are not version controlled.

NOTE: Only up-to-date versions of the documents are posted on the Engineering Department Only Drive. All other revisions (both electronic and hardcopy) should not be referenced.

2.0 General Information

2.1 Abbreviations and Acronyms

DER	Distributed Energy Resources
DOC	Distribution Operating Center
EV	Electric Vehicles

2.2 Definitions

2.2.1 Base Peak Load Forecasts

Base Peak Load Forecasts are load forecasts that are developed based on historical summer and winter loading conditions. These load forecasts do not include the incorporation of additional DER of EV penetration above and beyond what is inherent in historical loads.

2.2.2 Large DER

Any DER facility where the aggregate nameplate generation/energy storage at the point of common coupling is ≥ 500kW.

2.2.3 Minimum Daytime Load

The minimum daytime load is the annual minimum hourly sum of all measured tie point metering and Large DER metering between 7AM and 7PM.

3.0 Scope / Background

As part of the annual Distribution System Planning process, peak ten year load forecasts are developed for each distribution circuit and distribution substation transformer utilizing a linear trend analysis, wherever possible. Peak load forecast shall include the incorporation of future forecasts DER and EV charging load. In addition, future load projections reflect all permanent circuit reconfigurations, load transfers, and any known changes in key account customers (load additions or reductions). Separate forecasts are developed for the summer (May – September) and winter (November – March) seasons.

Due to the limited number of DCFC (Level 3) EV facilities and the uncertainty of where these facilities may be located it was determined that these would not be incorporated into distribution load projections. Instead these facilities will be treated similarly to how new large customer load additions are incorporated into distribution load projections in that they will be added to the projections per the customer schedule and engineering judgement.

Ten year minimum daytime load forecasts are developed for each distribution circuit and distribution substation transformer. Projected DER is subtracted from the three year historical minimum daytime load for each distribution substation transformer and circuit to establish the ten year minimum daytime load forecasts.

It is important to note that these load projections are considered a determination of future capacity requirements that serve as the basis for directing system modifications and not a "prediction" of specific load levels that will ultimately be experienced.

4.0 Base Peak Load Forecasting Methodology

The Base Distribution Load Forecasts are developed using the methodology below. Forecasts shall be created for each distribution circuit and distribution substation transformer for both the winter and summer seasons.

Summer forecasts shall be based on the previous five years of historical data when the projections are created. For example the 2022-2031 summer forecasts that are created for the 2021 planning cycle shall utilize historical summer peak loads from 2016 through 2020. The final published forecasts shall be for the summer of 2022 through 2031.

Due to the scheduling of the planning cycle winter forecasts shall utilize N-1 previous year's historical winter peak data. For example the 2022-2031 winter forecasts that are created for the 2021 planning cycle shall utilize historical winter peak loads from the winter of 2015 (November 2015 – March 2016)

through 2019 (November 2019 – March 2020). The final published forecasts shall be for the winter of 2021 (November 2021 – March 2022) through 2030 (November 2030 – March 2031).

4.1 Distribution Circuit Load Projections

Linear regression analysis is used to establish a 'best fit' trend line of the previous five year historical circuit load data. The slope of this line is then projected forward as the potential growth rate for a given circuit to yield the base load projection. One standard error is added to the projection for each year in order to provide a design margin for weather related variations and other forecasting uncertainties. This method is used when the growth rate is reasonable and positive and the standard error is 10% or less of the base load projection.

In some instances, linear regression analysis will result in an unreasonable growth rate, a negative growth rate or a standard error greater than 10%. In these instances, the linear regression trend line should be recalculated after dropping the values furthest away from the mean or using the previous three or four years of historical circuit load data. If an unreasonable growth rate, negative growth rate or unacceptable standard error still results, this method will be modified based on the following cases:

4.1.1 Positive Growth Rate with Standard Error >10%

Where a reasonable increasing trend results but the addition of standard error projects an unrealistic growth rate, the trend line shall be used to project the ten year load forecast and the standard error should not be included.

4.1.2 Negative Growth Rate or Unreasonable Positive Growth Rate

Where an unreasonable positive growth rate or a decreasing trend is the result of the linear trend analysis the circuit growth rate shall be set equal the system growth rate. The formula used to project the circuit is as follows:

$$\text{Projected Peak}_{\text{Year n}} = (\text{Circuit Peak Previous 3 years}) * \{1 + [\text{rate} * (n+1)]\}$$

n+1 is used in the projection formula to provide a design margin for weather related variations and other forecasting uncertainties.

This formula was derived on the basis that circuit load growth is more accurately estimated by projecting constant year-to-year incremental growth expressed in kVA. The typical compounding growth method will over estimate circuit load growth due to the compounding factor.

4.2 Distribution Substation Transformer Load Projections

Load projections for distribution transformers with historical peak data shall be calculated in the same manner as distribution circuit load projections described in section 4.1.

Sound engineering judgement shall be used to make sure the distribution substation transformer projections are reasonable and that they correlate with historical loads and projections of circuits supplied by the transformer.

In the event the transformer projections are unreasonable or there is no historical peak data available the following methods shall be used:

4.2.1 Unreasonable Distribution Transformer Projection

Where an unreasonable distribution transformer projection is the result of using the methods described in section 4.1 the load projections for the transformer shall be calculated based on the sum of the peak projected distribution circuit loads served by the transformer multiplied by a coincident circuit load factor. The historical coincident load factor for each year shall be determined using the following formula:

$$\text{Coincident Load Factor} = \frac{\text{Distribution Substation Transform Load}}{\sum \text{Distribution Circuit Loads}}$$

The maximum historical coincident load factor from the previous three years shall be used for projecting future loads. The coincident load factor used shall always be a number between 0 and 1. In some instances, such as years with missing or invalid circuit load data, the calculated coincident load factor may be a value greater than 1. These cases shall be discarded from the evaluation.

4.2.2 Transformers without Historical Data Supplying Circuits with SCADA Data

Transformer loading for units without historical monthly peak data which supply circuits that all have historical, coincident SCADA telemetry data shall be calculated using the procedure outlined below:

- The interval demand at each circuit supplied from the distribution substation transformer shall be obtained from SCADA.
- The interval data obtained from each circuit position shall be correlated to calculate an estimated aggregate peak load on the transformer.

The transformer loading shall then be projected in the same manner as transformers with historical data.

4.2.3 Transformers without Historical Data Supplying Circuits without SCADA Data

Projections for transformer that do not have historical monthly peak data and supply circuits that do not have historical, coincident SCADA telemetry data shall be calculated based on the sum of the peak projected distribution circuit loads served by the transformer multiplied by a coincident circuit load factor of 1.

It is understood that this method is conservative. In the event units projected in this manner are projected to be overloaded, field measurements (application of load loggers, installation of transformer metering, etc.) shall be taken to determine the severity of the loading concern.

4.3 Special Considerations

In all the following cases, care should be taken to properly document the methodology and reasoning used for all distribution circuit and distribution substation transformer load projections.

4.3.1 Large Interconnected DER Facilities and DER

The distribution load projection process shall include the impact of interconnected large scale DER facilities as well as the output or load offset by other DER projects. For the purposes of this guideline, a large DER facility shall be considered to be any facility where the aggregate nameplate generation at the point of interconnection is ≥ 500kW.

The development of load projections for circuits and distribution substation transformers with large DER facilities shall follow section 4.1 and 4.2 with all large DER facilities assumed to be offline with the exception of Unitil owned DER (PV or energy storage facilities).

When developing distribution load projections all Unitil owned DER (PV and energy storage) facilities shall be assumed to be on-line and fully operational. Unitil owned DER shall be reviewed to confirm that the load in which they are designed to serve or off-set can be restored utilizing traditional methods (load transfers to adjacent supplies, spare equipment, mobile substation, etc.) in the event the facility becomes unavailable.

The method for determining the previous circuit peak shall follow the procedure outlined below:

- The hourly interval demand at the substation circuit position and substation transformer shall be obtained from monthly substation inspection records, SCADA, or relay interrogation.
- The hourly interval DER interconnection(s) output shall be obtained from EMIS data, SCADA or relay interrogation.
- The hourly interval data obtained at the circuit position, transformer and DER interconnection(s) shall be correlated to calculate an estimated aggregate peak load on the circuit.

  Note: hourly interval data is required in order to accurately estimate the overall circuit peak load. Monthly peak demand values obtained from substation thermal metering is not adequate to determine circuit peak load since there is no way to correlate the timing of the circuit peak with the output of the generator nor is it possible to determine if the status of the generator (online/offline) at the time of the circuit peak.

4.3.2 Reserved Capacity Customers

The impact of customers with "reserved capacity contracts" shall be accounted for in the distribution load projection process. The development of load projections for circuits and substation transformers with reserved capacity customers shall follow section 4.1 and 4.2. The load associated with the reserved capacity service shall be removed from the historical load. Once the base projection of the remaining load is determined, the reserved capacity shall be added to each year of the projection.

The method for determining the previous circuit peak shall follow the procedure outlined below:

- The hourly interval demand at the substation circuit position and substation transformer shall be obtained from monthly substation inspection records, SCADA, or relay interrogation.
- The hourly interval demand at the reserved capacity service(s) shall be obtained from EMIS data, SCADA or relay interrogation.
- The hourly interval data obtained at the circuit position, transformer and reserved capacity service(s) shall be correlated to calculate an estimated aggregate peak load on the circuit without serving any load at the reserved capacity service.

4.3.3 Known Future Customer Additions

Any future large customer additions that are determined not to be part of "normal" load growth shall be added to each year of the circuit and substation transformer projections from which the new load will be served.

4.3.4 Load Transfers

Where load is transferred from one circuit to another in the previous year, the slope of the linear regression trend line and the standard error for each circuit shall be calculated based on the years prior to the transfer. However, the slope of the trend line represents the growth rate for the circuit prior to the load transfer. This will result in an annual growth rate that does not account for the transferred load. In order to correct this, the slope is scaled by a "load share multiplier" calculated using the following formula:

$$\text{Load Share Multiplier} = \frac{\text{Peak Load After Transfer}}{\text{Peak Load Before Transfer}}$$

The application of this method should be used with sound engineering judgment and all factors such as the amount and type (industrial vs. residential) of load being transferred shall be considered when determining if this method is applicable.

4.3.5 Winter Projections

Care should be taken such that circuits and distribution substation transformers that are historically summer peaking are not projected to become winter peaking unless sound engineering judgement determines this should be the case.

In the event linear regression analysis results in unreasonable winter load projections the winter projection shall be determined based on the summer projection multiplied by the proportion of the previous winter and summer peak circuit demands. The formula used to project the circuit is as follows:

$$\text{Projected Peak}_{\text{Year n/Year n+1}} = (\text{Summer Peak}_{\text{year n}}) * \frac{\text{Winter Peak Previous Year}}{\text{Summer Peak Previous Year}}$$

5.0 Final Distribution Load Forecasts

The distribution load forecasts shall include the incorporation of additional DER and EV penetration that is above and beyond what is inherent in base load projections.

5.1 Hourly Base Load Forecasts

The first step in the process to incorporate DER and EV into distribution load forecasts is to develop hourly base load forecasts for each distribution substation transformer and circuit. Hourly load forecasts are needed to calculate the overall load forecasts as the incorporation of EV and DER may shift the peak hour.

Historical hourly peak load profiles shall be established for each distribution substation transformer and circuit for both the winter and summer seasons. Hourly Base Load Forecasts are developed by calculating the average hourly load from the three peak days of the previous three years (less if three years is not available) for each circuit and transformer in which it is available. The average hourly peak load is then normalized to the peak of the transformer/circuit. For transformers and circuits that do not have hourly data available the normalized system peak load shall be used.

Each hour of normalized peak load is then multiplied by the distribution load forecasts to calculate hourly base load forecasts.

5.2 Incorporation of DER

DER forecasts shall be developed per the Distributed Energy Resource Projection Guideline (GL-DT-DS-12)

To incorporate Unitil's DER forecasts into the distribution load forecasts the projected incremental DER (DER Projection minus the in-service DER) shall be used to develop hourly DER projections for each distribution substation transformer and circuit.

Similar to the Hourly Base Load Forecasts normalized hourly peak DER output is calculated using the average hourly DER output of the large DER on the Unitil (all three DOCs) system for three peak days of the previous three years. Each hour of normalized average hourly peak DER output is then multiplied by the projected new DER.

Engineering judgement shall be used to determine a DER inherency factor. This factor is used to reduce the amount of forecasted DER that gets included in the forecast that is in addition to what is inherent in base forecasts. A general starting point is to use:

1- (Year1 New System Projected DER/Total-In-service System DER)

The hourly DER projections are then subtracted from the hourly base load forecasts to create distribution load forecasts with DER and without EV.

Due to the scheduling of the planning cycle distribution load forecasting shall utilize the previous year's DER forecasts. For example the 2021-2030 DER forecasts shall be incorporated into the 2022-2031 Distribution System Load Forecasts. For the purposes of distribution load forecasting the DER Forecasts for the final year of the Distribution System Load Forecast period (2031 in the example) should be assumed to be the same percentage increase for the final DER Forecast year and the N-1 final DER Forecast year (percentage increase from 2029 to 2030 in the example).

5.3 Incorporation of EV

EV forecasts shall be developed per the Electric Vehicle Load Projection Guideline (GL-DT-DS-13). The Baseline EV forecasts without DCFC (level 3) should be the utilized when incorporating EV into distribution load projections until Unitil implements proposed EV make-ready, TOU EV rates and other incentive programs to promote EV adoption. At such time, the High Rate EV forecast could be utilized.

Distribution circuit EV load projections shall be calculated based on the percentage of total DOC customers normally served. Distribution substation transformer EV load projections shall be the sum of circuits served EV load projections.

Engineering judgement shall be used to determine an EV inherency factor. This factor is used to reduce the amount of forecasted EV that gets added to the forecasts in addition to what is inherent in base forecasts. With EV penetration in its infancy this factor should be set 100% and should be reduced as EV penetration increases throughout Unitil's system.

The hourly EV projections are then added to the hourly base load forecasts to create distribution load forecasts with EV and without DER.

As is the case with the incorporation of DER the incorporation of EV projections shall utilize the previous year's EV forecasts. For example the 2021-2030 EV forecasts shall be incorporated into the 2022-2031 Distribution System Load Forecasts. For the purposes of system load forecasting the EV Forecasts for the final year of the Distribution System Load Forecasts (2031 in the example) should be assumed be the same percentage increase for the final EV Forecast year and the N-1 final DER Forecast year (percentage increase from 2029 to 2030 in the example).

5.4 Final Load Forecasts

Final Distribution Load Forecasts are developed by subtracting the hourly DER forecasts from the base distribution load forecasts and adding the hourly EV forecasts. The resulting maximum hourly load forecast for each distribution substation transformer and circuit is the Final Winter and Summer Distribution Forecasts that incorporates both DER and EV projections.

6.0 Minimum Daytime Load Forecasting Methodology

Ten year Minimum Daytime Load Forecasts shall be developed for each distribution substation transformer and circuit.

The historical minimum daytime load shall be the transformer/circuit's three year historical minimum load between 7AM and 7PM. In the event three years of historical data is unavailable, the minimum

load shall be the minimum of the available years of data. Minimum loads associated with large outages and/or exclusionary outage events shall be excluded from this analysis.

In the event actual minimum daytime load data for a particular circuit is not available, the minimum daytime load shall be assumed to be 30% of the circuit's lowest historic annual peak load over the previous three years. In the event the minimum daytime load data is not available for a transformer, the minimum daytime load shall be assumed to be the sum of the circuits supplied via the transformer's minimum daytime loads.

For the purposes of Minimum Daytime Load Forecasts, the historical minimum daytime load data shall include the output of all distributed generation including those with a nameplate capacity of 500kW or more.

When utilizing actual minimum daytime load data, the DER approved for install and the incremental Projected DER (DER Projection minus the in-service DER) for each year shall be adjusted per the typical ratio of DER output to DER nameplate of large DER on the Unitil system (across all three DOCs) at the historical minimum daytime load hour. The adjusted incremental DER Projections for each year shall be subtracted from the circuits/transformer minimum daytime load to create ten year Minimum Daytime Load Forecasts for each distribution substation transformer and distribution circuit on the system.

When actual minimum daytime load data is not available and the minimum daytime load is estimated based on peak load, all full DER Forecasts (all installed, approved for installation and incremental projected DER forecasts) for each year shall be adjusted per the typical ratio of DER output to DER nameplate of large DER on the Unitil system (across all three DOCs), at the historical minimum daytime load hour. The adjusted full DER Forecasts for each year shall be subtracted from the circuits/transformer minimum daytime load to create ten year Minimum Daytime Load Forecasts for each distribution substation transformer and distribution circuit on the system.

7.0 Distribution Load Forecast Publications

A publications shall be issued annually that documents the final Winter and Summer distribution peak load forecasts and Minimum Daytime Load Forecasts for each distribution substation transformer and circuit. All three DOC's forecasts shall be published in the same document. The base peak load forecasts and forecasts with and without DER and/or EV for each distribution substation transformer and circuit shall be included in the appendices of the publication.