Public Service Company of New Hampshire

d/b/a Eversource Energy

Least Cost Integrated Resource Plan

August 23, 2019

I. INTRODUCTION

On June 19, 2015, Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource" or the "Company") submitted its Least Cost Integrated Resource Plan ("LCIRP") as required by RSA 378:38 and Order No. 24,659 (May 1,2014), as clarified by the Commission in Order No. 25,676 (June 12, 2015) (the "2015 Plan"). Following a period of review, a settlement agreement relating to that plan was reached between Eversource and the Commission Staff which was filed on January 23, 2017, and approved by the Commission in Order No. 26,050 (August 25, 2017). The settlement agreement relating to the 2015 Plan provided, in relevant part, that at the time it filed its next LCIRP, Eversource would provide the information required by RSA 378:38, as well as additional information sought by the Commission Staff.

Pursuant to RSA 378:38, "each electric and natural gas utility, under RSA 362:2, shall file a least cost integrated resource plan with the commission within 2 years of the commission's final order regarding the utility's prior plan, and in all cases within 5 years of the filing date of the prior plan." In that Eversource's 2015 Plan filing was made on June 19, 2015, and Order No. 26,050 approving a settlement agreement between Eversource and the Staff relating to that plan was issued on August 25, 2017, that order provided, in relevant part, that Eversource's next LCIRP would be due within 2 years of that date, or August 25, 2019.

On February 12, 2019, the Commission Staff submitted a long-pending recommendation on grid modernization in Docket No. IR 15-296. That recommendation summarized an extensive review by the Staff of issues relating to grid modernization following on earlier work that had been undertaken by a large stakeholder group, and which had resulted in a report from the Staff's consultant, Raab Associates, Ltd., on March 20, 2017. Among other things, the Staff's recommendation proposed that the LCIRP be replaced by a new submission, an Integrated

Distribution Plan or IDP. This new IDP, the form of which is not yet settled, would have some elements of the old LCIRP as well as new requirements. In recognition of the possibility of requiring this new submission for Commission review and approval, the Staff recommended the following:

> The IDP will require approximately 12 months to develop, using the comprehensive LCIRP template with the incorporation of the grid modernization initiatives plus an engaged stakeholder process. Eversource and Liberty Utilities are required to file their next LCIRP to the Commission by August 25, 2019, and July 1, 2019, respectively, and Unitil is required to file its LCIRP by January 9, 2020. Staff recommends that, if necessary, the utilities request that the LCIRP filing requirement be waived by the Commission, pursuant to RSA 378:38-a, in order to enable the utilities to submit the more robust, integrated, and transparent IDPs.

February 12, 2019 Staff Recommendation in Docket No. IR 15-296 at 67.

In view of that recommendation, on April 9, 2019, Eversource filed a motion seeking a waiver of the requirement to make an LCIRP filing by August 25, 2019. More specifically, Eversource requested that a waiver "persist until the IDP, or similar, requirement is established" and that when the requirement for the IDP became established "the requirements of the LCIRP statute be waived, as may be necessary, in favor of a submission aligned with those new requirements." April 8, 2019 Motion of Eversource in Docket No. DE 15-248 at 7.

On June 14, 2019, the Commission issued Order No. 26,262 in Docket No. DE 15-248 and partially granted the waiver requested by Eversource. Particularly, the Commission concluded that in light of its "pending investigation on grid modernization, IR 15-296, and the anticipated timing of an IDP filing. . . a waiver of the August 25, 2019, filing deadline for Eversource will allow a more efficient use of utility resources." Order No. 26,262 at 5. Accordingly, the

Commission did not require a submission by August 25, 2019 containing the elements of a full LCIRP filing.[1]

In granting its waiver, however, the Commission ordered that Eversource make a more limited filing, and that the "purpose of that filing will be to ensure that Eversource is adhering to the commitments made in its prior approved LCIRP." Id. at 6. More pointedly, the Commission ordered:

> Our prior approval of Eversource's 2015 LCIRP contained a number of specific deliverables and we will require updates of those no later than August 25, as listed below:
>
> • Confirmation that the utility is currently following the process of system planning utilizing those established procedures, criteria, and policies outlined in its 2015 LCIRP, and achieving the objectives included in its 2015 LCIRP;
>
> • A copy of the Eversource-UES and Eversource-NHEC Joint Recommendations Report from each of the most recent joint planning meetings with UES and with NHEC;
>
> • 2019 Organization charts for field distribution operations, planning, and engineering;
>
> • An updated crew complement report (include bucket crews, digger crews, and troubleshooters assigned to each area work center in all five regions) for 2017, 2018, and 2019;
>
> • The Company's evaluation of targeted energy efficiency solutions for potential projects for 4 & 12 kV substations due to loading;
>
> • An update on the HeatSmart customer recertification results;
>
> • A copy of the most recent list of proposed capital projects which were presented to senior management for consideration of approval; and
>
> • Details regarding the steps taken through each state of the Planning Process Flow for each of the highest-cost distribution capital projects with a status of In Service, Under Construction, or Planned, within the prior two years, and a demonstration of how the LCIRP plan was followed through the planning process.
>
> We will not require Eversource to update its distribution automation plan or its customer engagement platform in the August 25, 2019, filing. Although those items were included in the order approving the 201 5 LCIRP. they will be covered in more detail in the IDP.

[1] The Commission also declined to waive the 5-year requirement of RSA 378:38, but that conclusion does not bear upon this submission.

Id. at 6-7. Consistent with the Commission's directive in Order No. 26,262, Eversource includes in this submission the updated information required by the Commission.

II. UPDATED DELIVERABLES

1) Confirmation that the utility is currently following the process of system planning utilizing those established procedures, criteria, and policies outlined in its 2015 LCIRP, and achieving the objectives included in its 2015 LCIRP

The 2015 LCIRP, was limited to Eversource's distribution and transmission planning and stated the following with regard to the objectives of the plan:

> Eversource serves more than 500,000 homes and businesses in New Hampshire and is primarily responsible for the provision of safe and reliable electric service to its retail customers. Additionally, the Company also provides wholesale delivery service to the New Hampshire Electric Cooperative (NHEC), Unitil Energy Systems (UES) and several municipal electric companies. Under the distribution section of this Plan, Eversource describes how it fulfills its responsibility to provide service to all of its distribution customers, operate and maintain its distribution system, connect new customers, plan and build distribution plant for customers' peak demand requirements, and offer energy efficiency and demand side management opportunities to its customers. The distribution section also outlines the Company's system peak load forecasting methodology and how the forecast is used to assess future system needs.

2015 Plan in Docket No. DE 15-248 at 1.

With respect to the distribution system, the merger of Northeast Utilities and NSTAR in 2012 to form what is now Eversource Energy has provided an opportunity for the operating entities in New Hampshire, Massachusetts and Connecticut, including the Company, to evaluate their distribution planning criteria and work toward developing standards across all companies that provide a more reliable and resilient electric distribution system. Through this process, which continues today, Eversource has adopted various company-wide procedures and criteria, including SYSPLAN 010 – Bulk Distribution Substation Assessment Procedure, SYSPLAN 008 – Calculation and Documentation of Bulk Distribution Transformer Ratings, and an econometric load forecast methodology. As with the previous methods that were specific only to Eversource in New Hampshire, each of these company-wide procedures, criteria, and policies support Eversource's overall goal of designing and operating an electric system that safely meets the needs of customers of all types at the lowest reasonable cost. Where new company-wide procedures have not yet been developed, the planning criteria referenced in the 2015 LCIRP continue to be applied.

On the transmission system, in May 2015, ISO New England began implementing changes to the regional and interregional transmission planning process to comply with the directives in Order No. 1000 issued by the Federal Energy Regulatory Commission ("FERC"). That order established new electric transmission planning and cost allocation requirements for public utility transmission providers across the country. Additional information can be found at https://www.iso-ne.com/committees/key-projects/implemented/order-no-1000. Eversource complies with all FERC and ISO-NE Transmission Planning processes.

Within Eversource, the project approval process has been enhanced since 2015 such that distribution substation projects are now reviewed by committees that include subject matter experts from across the Eversource Energy system. A project is first presented at the Solution Design Committee ("SDC") for a technical review and challenge of the project. The make-up of the SDC may change from project to project, but will generally include management personnel from the following departments: Protection and Control Engineering, Substation Design Engineering, System Planning, Transmission Business and Quality Assurance, Transmission Line Engineering, Substation Technical Engineering, Project Management, Asset Management, System Operations, and Siting and Construction Services. Once a project has been approved by the SDC the project is submitted to the Eversource Project Approval Committee ("EPAC") for financial approval. Distribution Line projects are reviewed from a technical and financial basis by the New Hampshire Project Approval Committee which consists of members from multiple engineering and operational disciplines. Both substation and line projects are approved by designated levels of management based on the total estimated cost of the project. This approval is documented in the PowerPlan software system.

Ultimately, funding of distribution projects must be coordinated and approved through the annual budget approval process which has not changed from what was provided in the 2015 LCIRP proceedings. It should be noted that the project approval process has evolved since 2015 and therefore the processes, form titles, and committee titles have been modified over this period. Please see pages 5 – 14 of the May 28, 2019 testimony of Erica Menard in the Company's rate case in Docket No. DE 19-057 for a detailed description of the capital planning and approval process both before and after 2015.

2) A copy of the Eversource-UES and Eversource-NHEC Joint Recommendations Report from each of the most recent joint planning meetings with UES and with NHEC

As noted in Eversource's 2015 Plan (page 11), an Eversource - UES Joint Recommendations Report is generated each year. Eversource and NHEC, however, do not generate such reports annually, but will meet periodically and perform joint planning when mutually agreed. Please see the 2018 Eversource-UES Joint Planning Report attached as Attachment A.

With respect to NHEC, a joint planning report with NHEC has not been generated. Regular contact and coordination have been maintained and specific studies are performed on an ad hoc basis. Below are examples of planning interactions with NHEC since the time of the 2015 Plan. Coordination between field engineering personnel of both companies occurs on a regular basis as well as:

2016 – NHEC Moultonborough PV Interconnection study;

2016 – Discussed 377 line regulators and NHEC Raymond substation rebuild;

2017 – Loading data provided to NHEC for Beebe River and North Woodstock Substations;

2017 – NHEC shared its Long Range System Plan with Eversource;

2018 – NHEC and Eversource Planning reviewed the loading on the 355 line for NHEC customer growth;

2018 – Reviewed possible new metering point on one of the White Lake lines to split existing NHEC White Lake load.

3) 2019 Organization charts for field distribution operations, planning, and engineering

Please see the organization charts included as Attachments B and C to this submission.

4) An updated crew complement report (include bucket crews, digger crews, and troubleshooters assigned to each area work center in all five regions) for 2017, 2018, and 2019

Please see Attachment D included with this submission for the information. Please note that the supplied crew count report does not include authorized open positions which Eversource is working to fill.

5) The Company's evaluation of targeted energy efficiency solutions for potential projects for 4 & 12 kV substations due to loading

Each year the company identifies non-bulk transformers that are loaded above 85% of the TFRAT or long-term emergency rating. A growth rate is applied (typically the same growth rate as the bulk substation that provides the supply) to determine if the transformer is expected to exceed its TFRAT rating within the next 10 years. For each transformer that is forecasted to exceed its TFRAT rating, it is determined whether load served by the transformer is a candidate for targeted energy efficiency which could be implemented to defer capital investment. Most of the transformers are not forecasted to exceed the TFRAT rating within the next ten years. A few of the transformers will be addressed with projects that are associated with asset condition and reliability. The results of this effort are summarized in the spreadsheet attached (Attachment E) with an explanation of whether targeted energy efficiency is a viable alternative to a more traditional investment.

Also, as described in the July 31, 2019 testimony of Charlotte Ancel in Docket No. DE 19-133,[2] the Company has reviewed the potential for targeted energy efficiency in the context of its Westmoreland Clean Innovation Project. That review was not specifically undertaken to address loading, but as part of a more comprehensive solution to a reliability concern. Nonetheless, there review did include a review of targeted energy efficiency solutions. Additional detail on the review and the associated proposal for targeted efficiency can be found in Ms. Ancel's testimony.

Additionally, in 2019, the Company received approval to implement a demand reduction pilot program targeting Commercial & Industrial ("C&I") customers as part of its energy efficiency programs. As with the Westmoreland project, this proposal was not intended to address loading issues, but to avoid costs associated with peak demand. Information on that pilot proposal can be found in the January 18, 2019 filing Docket No. DE 17-136.

6) An update on the HeatSmart customer recertification results

Beginning in late 2015 and continuing through early 2016, the Company began the process of circulating letters (Attachment F, page 1) and recertification forms (Attachment G) to

[2] Ms. Ancel's testimony was initially submitted on May 28, 2019 testimony in the Company's rate case in Docket No. DE 19-057, but was subsequently removed from the rate case filed as a separate docket, Docket No. DE 19-133.

customers. There were 3,074 letters and recertification forms sent and the Company received 2,497 completed forms from customers. Approximately 580 customers (10%) did not respond to the first request and were sent a second letter (Attachment F, page 2) in the 2nd through 4th quarters of 2016.

Of the customers who were notified and responded, approximately 2,100 customers were recertified for the HeatSmart program by confirming they have an approved back-up heating source and those customers remained on the HeatSmart program. The company will continue periodic review following the current HeatSmart summer period, including outreach to customers who have not completed the recertification process.

7) A copy of the most recent list of proposed capital projects which were presented to senior management for consideration of approval

Please see the project list included as Attachment H to this submission

8) Details regarding the steps taken through each state of the Planning Process Flow for each of the highest-cost distribution capital projects with a status of In Service, Under Construction, or Planned, within the prior two years, and a demonstration of how the LCIRP plan was followed through the planning process.

Documentation is provided for the following three projects: Webster/Daniel Substation Upgrade; Emerald Street Substation Upgrade; and Rochester 4kV Conversion

i) Webster/Daniel Substation Upgrade (Distribution Cost $19.69 million)

The need to address loading on the Webster substation was identified in distribution planning ten-year studies as early as 2008 and was included in every ten-year study report which followed. A Webster Substation Study was conducted in 2015 to consider alternatives and determine the preferred solution. A Project Authorization Form ("PAF") was presented to the

Eversource Project Approval Committee ("EPAC") in March of 2016. A final Supplement Request Form was presented and approved at EPAC in August of 2018 which documented the basis for costs which exceeded the estimate presented in the PAF.

This project was placed in-service in 2018 and consisted of replacing three smaller 1950's vintage transformers with two larger transformers within the existing Webster Substation. The project also created a 34.5kV switching station with two station capacitor banks, a normally open bus-tie switch, an automatic bus restoral scheme, new transformer and line circuit breakers (which replaced oil circuit breakers), and a dedicated circuit breaker to serve the NHEC Webster substation. Additional details are included in Attachments I, J and K which are referenced above and demonstrate how Eversource adhered to its planning principles as described in the 2015 Plan throughout the process of developing this project.

<u>ii. Emerald Street Substation Upgrade</u> (Distribution Cost (est.) $17.635 million)

The Emerald Street Substation Upgrade project is the second phase of a comprehensive area solution in the Keene area. Transformer loading concerns were identified in annual loadflow studies as early as 2008. Asset condition, reliability, circuit breaker interrupting ratings, and forecasted load issues at the Emerald Street Substation (also referred to as the Keene Substation) prompted the Keene Area Distribution System Study in 2012. The North Keene Substation was constructed and placed in service in 2016 as the first phase of the area solution. Because essentially all load in that area was, at the time, served out of the Emerald Street Substation, it was necessary to construct a new substation to allow for the rebuild of the existing Emerald Street Substation while maintaining reliable electric service to the customers served in that area. Additionally, the second substation provided a redundant source for the area, and the ability to shift or redirect load and supply flows, resulting in significant reliability benefits for the area.

A Technical Authorization Form ("TAF") was submitted and approved in November of 2016 for the rebuild of the Emerald Street Substation. With this approval, initial funding for engineering was authorized. A PAF for long lead time material was submitted and approved in March of 2017. A PAF for full funding was submitted and approved in September of 2017. While developing the Outage and Energization plan, a change in scope was required to address unacceptable levels of risk resulting from outages during construction. As a result, a Solution Selection Form ("SSF") with the new project scope was submitted and reviewed by the Solution Design Committee in January of 2019. A Supplement Request Form which included the revised scope and cost estimate was submitted and approved at EPAC in May of 2019. In addition to the project covering the substation assets, a PAF was also submitted and approved in March of 2018 for distribution line work associated with constructing the getaway cables and risers for each of the circuits emanating from the new switchgear. Additional details are provided in Attachments L through R which are referenced above and demonstrate how Eversource adhered to its planning principles as described in the 2015 Plan throughout the process of developing this project. This project is under construction with an estimated in-service date of December 2020.

<u>iii. Rochester 4kV Conversion</u> (Distribution Cost $11.532 million)

The Rochester 4kV Conversion is a project that encompasses three non-bulk substations and the conversion of 4kV circuits in Rochester, New Hampshire. The project was initiated primarily for asset condition of the Signal Street 34.5 – 4.16 kV 1954 vintage transformer. Other drivers included protection limitations, lack of transformer or circuit capacity under contingency, and limitations of 4kV distribution. A comprehensive area study was completed in January of 2017. The recommended solution included changing a dual voltage distribution transformer at Portland Street Substation from 4.16kV to 12.47 kV, rebuilding Twombley Street Substation with a larger transformer, converting the 4kV circuits to 12kV, and retiring the Signal Street Substation.

A TAF was submitted and approved in January of 2017 for the proposed substation and distribution line upgrades. A PAF for the distribution line 4kV conversion work was approved in February of 2018 at the New Hampshire Project Approval Committee. A PAF for the Twombley Street Substation Rebuild project was approved in May of 2019 at the EPAC. Additional details are included in Attachments S through V which are referenced above and demonstrate how Eversource adhered to its planning principles as described in the 2015 Plan throughout the process of developing this project. This project is under construction with an estimated in-service date for the Twombley Substation of June 2020.

Eversource / Unitil Energy Systems

2018 Joint Planning Report

December 13, 2018

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1 EXECUTIVE SUMMARY

Eversource and Unitil have conducted the annual joint planning meeting(s) and completed the joint planning process for 2018. Planning departments from both companies were represented at the meeting(s) and loading of joint facilities under basecase and contingency configurations were reviewed.

This report summarizes the findings of the joint planning process. The Eversource 2019-2028 Loadflow Study and the Unitil 2019-2028 Electric System Planning Studies were used as the basis for identifying constraints for the years 2019-2028. Alternatives are developed and evaluated per each company's planning and design guidelines. Evaluation criteria include total cost in today's dollars, net present value, system benefit and technical preference.

The 2018 Eversource and UES joint planning process did not identify any required Capital system improvement projects at the present projected load levels. However, the following non-capital modifications are recommended as a result of the joint planning effort:

- In 2018 Eversource will review the protection settings of the 3810X and 3260X breakers at Great Bay substation and implement new settings prior to summer load in 2019 to accommodate loading each Breaker position to the LTE rating of the transformer. The need for this modification is that Unitil expects to exceed 80% of the minimum overcurrent pick-up setting of on the 3810X relaying for loss of the 3351 line.
- Starting in 2020 Unitil will switch an additional [redacted] during the summer load season. The need for this additional switching is due to the new ratings of the Great Bay TB141 transformer.

2 INTRODUCTION

Unitil is a transmission customer of Eversource in New Hampshire. Unitil is provided 34.5 kV service at four Eversource distribution substations; Oak Hill and Garvins in Concord, Timber Swamp in Hampton, and Great Bay in Stratham. Additionally, Unitil is supplied 115 kV service at Unitil's Kingston substation in Kingston and Broken Ground substation in Concord. Three of the distribution substations supply both Unitil and Eversource distribution load. Due to the joint nature of the Eversource distribution and transmission facilities that supply Unitil Eversource and Unitil participate in a joint planning process to develop short term and long term plans for these areas that represent the best interests of all customers as a whole.

Although transmission needs are discussed, the joint planning process is a distribution planning effort and any recommendations that have transmission implications need to be reviewed by Eversource Transmission Planning and ISO-NE.

The joint planning process is an annual process that typically consists of Unitil and Eversource developing independent system load projections and loadflow models. Unitil and Eversource exchange load projections and incorporate them into their loadflow models. As needed Eversource will provide Unitil with an updated transmission loadflow model that Unitil will incorporate the Unitil distribution model into and return to Eversource for use in their studies. Unitil and Eversource complete separate planning studies (Eversource Loadflow Study and Unitil Electric System Planning Studies). With the study work complete joint meetings are held to discuss the results and project scopes and estimates are developed for any identified constraints that affect joint facilities.

3 RELEVANT SYSTEM CHANGES

Relevant system changes since the release of the previous Joint Planning Report are described below:

3.1 Re-rate of Eversource Transformers

Eversource has recently reviewed and modified their transformer rating methodology. The previous TFRAT method is no longer being used and a new methodology has been implemented. The new LTE ratings assume a 75% preload, which will reduce the LTE rating of transformers that are loaded greater than 75% of their normal rating pre-contingency. The following table listed the previous and current summer ratings of the Eversource transformers that supply UES:

Transformers	Nameplate Capacity (MVA)	Previous TFRAT Rating (MVA)	Current Rating	
			Normal (MVA)	LTE (MVA)
Garvins TB39	60	69	67	79
Garvins TB51	60	70	67	79
Oak Hill TB15	44.8	52	44	53
Oak Hill TB84	44.8	53	45	49
Timber Swamp TB25	140	165	140	180
Timber Swamp TB69	140	161	140	163
Great Bay TB141	44.8	52.6[1]	44	51

3.2 Changes to Eversource Planning Criteria

Eversource has recently modified their planning criteria. Below is a summary of the significant changes that affect the jointly used facilities:

- No load can remain out of service for loss of a bulk transformer.
- All elements shall be loaded below normal within 24 hours.
- Restoration switching is limited to three load block transfers (must be remote controlled) following contingent loss of an element.
- Does not allow for the offloading of unaffected elements to provide capacity to restore outaged load

[1] Great Bay TB141 has an operation limit of 46 MVA. [redacted] The alarm set point is 90°C top oil temperature. The trip is set at 100°C top oil temperature.

3.3 Second Transformer at Eversource Rimmon Substation

Eversource completed the installation of a second 44.8 MVA, 115-34.5 kV transformer at Rimmon substation in 2016. This unit helps address contingent loading concerns at Rimmon, Eddy and Garvins substations.

3.4 Kingston System Supply and 3818 Circuit

Unitil placed the new UES Kingston system supply substation in-service in 2016. This project addressed loading concerns associated with Eversource's Kingston substation. Unitil is no longer supplied via the Eversource Kingston substation, which provided Eversource with capacity for a future distribution circuit. To accommodate Unitil's Kingston substation Eversource constructed Peaslee substation, a new 115 kV switching station, and a second 115 kV transmission line from the H141/R193 right-of-way to Kingston/Peaslee.

In 2017 Unitil and Eversource completed the construction of a joint 34.5 kV line along Route 111 in Danville. This line consists of Unitil's 22X1 circuit and the Eversource 3818 circuit both originating from the companies' respective Kingston substation. The construction of this line allowed both companies to address reliability concerns associated with their existing distribution circuits in the area, including the towns of Kingston, Danville, Hampstead and Chester.

3.5 Broken Ground System Supply

Unitil placed the new UES Broken Ground system supply substation in-service in 2017. This project addressed loading concerns associated with Eversource's Garvins and Oak Hill substations. Unitil's Hollis load was disconnected from the Eversource 318 line and a portion of Unitil's 38 line load was transferred to Broken Ground. To accommodate Unitil's Broken Ground substation Eversource constructed Curtisville substation and made upgrades to Farmwood substation.

Until the upgrades to Farmwood substation are complete Unitil has to be able to reduce Broken Ground loading to [redacted] or less following various 115 kV contingencies in the area. The Farmwood upgrades are currently expected to be completed by the end on 2018.

4 BASECASE REVIEW

The following table summarizes the percent loading of the jointly used transformers.

Year	Location/Element	Percent Loading
2020	Great Bay TB141 Transformer	90% of Normal (40.5 MVA)
2028	Garvins TB39 Transformer[1]	78% of Normal (46.8 MVA)
	Garvins TB51 Transformer[1]	79% of Normal (47.1 MVA)
	Oak Hill TB15 Transformer[1]	81% of Normal (36.2 MVA)
	Oak Hill TB84 Transformer[1]	80% of Normal (35.8 MVA)
	Great Bay TB141 Transformer	97% of Normal (43.5 MVA)
	Timber Swamp TB25	62% of Normal (86.7 MVA)
	Timber Swamp TB69	27% of Normal (37.4 MVA)

[1] Assumes SES Concord and all area hydroelectric generators are off-line

The Great Bay TB141 transformer is expected to exceed 90% of its normal rating in 2020, requiring additional load to be transferred from [redacted].

5 CONTINGENCY EVALUATION

The following section describes the power flow simulation results for contingent loss of jointly used power transformers, any contingency that is expected to load jointly used infrastructure over its normal rating, and contingencies which identify deficiencies that have alternatives requiring modifications to jointly used facilities in the next ten years.

The switching described below is a guide and is not meant as step by step switching procedures to be implemented in the field.

All scenarios below assume SES Concord and all area hydroelectric generators are off-line

5.1 Loss of Garvins TB51 Transformer

(Garvins TB51 transformer fault)

Initial Event:

[redacted]

Automatic Restoration:

[redacted]

Unitil Switching Procedures:

[redacted]

- All **Unitil** load restored

Eversource perform switching to restore load:

[redacted]

- All **Eversource** Load restored

System Concerns:

2019:

[redacted]

2028:

[redacted]

... install Eversource [redacted]..

5.2 Loss of Garvins TB39 Transformer
(Garvins TB39 transformer fault)

[redacted]

5.3 Loss of Oak Hill TB84 Transformer
([redacted])

Initial Event:

[redacted]

Unitil Switching Procedures:

[redacted]

- All load restored

Note: Additional switching required if [redacted] lockout on overcurrent.

System Concerns:

2019:

[redacted]

2028:

[redacted]

Eversource Switching Procedures:

1. Eversource to transfer [redacted] substation as needed to alleviate loading concerns.

REDACTED

... install Eversource [redacted]..

5.4 Loss of Oak Hill TB15 Transformer

([redacted])

[redacted].

5.5 Various UES-Capital Contingencies

[redacted].

- [redacted]

[redacted].

- [redacted]

5.6 Loss of Timber Swamp TB25 Transformer

([redacted])

Initial Event:

[redacted]

Automated Switching

[redacted]

No Manual Switching Required

- No load out of service

System Concerns:

2019:

[redacted]

2028:

[redacted]

5.7 Loss of Timber Swamp TB69 Transformer

([redacted])

[redacted]

5.8 Loss of Great Bay TB141 Transformer

(Great Bay TB141 transformer fault)

Initial Event:

[redacted]

Unitil Switching Procedures:

[redacted]

- All load restored

System Concerns:

2019:

[redacted]

2028:

[redacted]

5.9 Line Contingencies

There are no line contingencies that cause elements to exceed their normal ratings. However, for the loss of Unitil's [redacted]

6 ADDITIONAL ITEMS DISCUSSED

In addition to the traditional basecase and N-1 contingencies the joint planning group also discussed the following items.

6.1 Timber Swamp Substation – Loss of Both the TB25 and TB69 Transformers

[redacted]

[redacted]

[redacted]

6.2 Split Oak Hill/Penacook for 115 kV Contingencies

Due to the normal configuration of Oak Hill and Penacook Unitil was informed by the ESCC that anytime a Farmwood substation breaker was open or out of service an Oak Hill Transformer had to be removed from service or the Oak Hill bus tie and one of the lines between Oak Hill and Penacook (317 or 3122) had to be open at Penacook or Oak Hill to avoid the 34.5 kV system becoming a transmission path following the loss of a [redacted] outage.

During the next annual planning process Unitil plans to study the possibility of splitting the Oak Hill and Penacook 34.5 kV buses to avoid the need to remove components of the distribution system from service due to maintenance or faults on the transmission system. In the event this appears feasible it will be discussed in more detail during next year's joint planning process.

7 CONCLUSION

The 2018 joint planning process did not identify any system deficiencies that require capital investment. The following two non-capital modifications were identified:

- 2019 – Eversource to review 3810X and 3260X protections settings and implement new settings as required.
- 2020 - Unitil to switch an additional [redacted] during the summer load season.

Additionally, two items were identified as requiring additional study:

- Loss of [redacted].
- Splitting of the Oak Hill and Penacook 34.5 kV buses.

8 ACCEPTANCE

This joint planning report is accepted by both Eversource and Unitil as meeting the needs for the long term planning of jointly used distribution facilities.

Russel Johnson ____ 12/13/2018 ____
Manager – System Planning, Eversource Date

12/20/2018
Director –Engineering, Unitil Date

Eversource Electrical Engineering

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  Engineering,
  Electric Operations
  - **Asim Fazlagic**
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    Manager
    Distribution Standards
  - **John M Zicko**
    Director
    Substation Design
    - **Thelma Brown**
      Manager
      Substation Design (NH)
  - **Roderick S Kalbfleisch**
    Director
    Substation Technical
    - **Kevin P Duhaime**
      Manager
      Substation Technical (NH)
  - **John C Case**
    Director
    Transmission Line
    - **Cory J Liu**
      Manager
      Underground Transmission Line
      - **Donald S DiBuono**
        Lead Engineer (NH)
  - **George P Wegh**
    Director
    Protection & Control
    - **Dennis J Western**
      Manager
      Protection & Control (NH)

Eversource Electrical Engineering

As of 07/01/2019

- **Paul R Renaud**, Vice President, Distribution Engineering
  - **James C Eilenberger**, Director, Distribution Engineering (NH)
    - **Thomas C Mitchell**, Manager, GIS
    - **Lee G Lajoie**, Manager, System Resiliency
    - **Michael J Busby**, Manager, Field Engineering & Design, Eastern
    - **Marc W Pilotte**, Manager, Field Engineering & Design, Central
    - **Mark F Fraser**, Manager, Field Engineering & Design, Western
    - **Samuel D Bosse**, Manager, Field Engineering & Design, Northern
    - **George R Loura**, Manager, Field Engineering & Design, Southern
  - **Samuel Noel Woolard**, Director, Distribution Engineering (CT)
  - **Amin R Jessa**, Director, Distribution Engineering (MA)
  - **Umair Zia**, Director, Distribution Engineering (MA) & Distributed Generation
    - **Richard C Labrecque**, Manager, Distributed Generation (NH)

Eversource Electric Operations

As of 07/01/2019

- **William J Quinlan**, President, Electric Operations
  - **Joseph A Purington**, Vice President, Electric Operations
    - **Eric Sutton**, Director, Substation Operations
      - **Perry L McKinney II**, Manager, Field Communications
      - **Christopher A Wayland**, Manager, Substation Operations & Maintenance
    - **Mark A Sandler**, Director, Field Operations
      - Manager, Regional Operations Western
      - Manager, Regional Operations Southern
      - Manager, Regional Operations Northern
      - **Jason M Yergeau**, Manager, Regional Operations Central
      - **Michael C Lee**, Manager, Regional Operations Eastern
      - **Thomas W Davis**, Manager, Transmission Construction & Maintenance
    - **Brian J Dickie**, Director, System Operations
      - **Timothy L McHugh**, Manager, Transmission System Operations
      - **Donald R Nourse**, Manager, Distribution System Operations

NH Electric Field Operations
Working Foreman / Lineworker Headcount Jan 2017 - July 2019

AWC	Jan-17		Feb-17		Mar-17		Apr-17		May-17		Jun-17	
	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker
Nashua	7	6	7	6	5	6	5	6	5	7	5	6
Derry	5	6	5	6	4	6	4	6	3	6	3	5
Tilton	9	8	9	9	9	9	9	9	8	9	9	8
Berlin	2	3	2	3	2	3	2	3	2	3	2	3
Chocorua	4	4	4	4	4	4	4	3	4	3	4	2
Lancaster	6	5	6	6	6	6	6	6	6	6	6	6
Bedford	10	8	10	7	9	7	9	9	9	9	9	8
Hooksett	11	10	11	10	11	11	10	11	10	11	10	11
Rochester	9	9	9	9	8	9	8	9	9	8	9	8
Epping	5	4	5	4	5	4	5	4	5	4	5	4
Portsmouth	4	5	4	5	4	5	4	5	4	5	4	5
Newport	6	6	6	6	6	6	6	6	6	6	6	6
Keene	10	10	10	10	10	10	10	10	10	10	9	10
Milford	0	0	0	0	0	0	0	0	0	0	0	0
AWC Sub Total	88	84	88	85	83	86	82	87	81	87	81	82
AWC Total	172		173		169		169		168		163	
Transmission	2	4	2	4	2	4	2	4	2	4	2	4
Troubleshooters		17		17		17		16		16		16
Total All	195		196		192		191		190		185	

NH Electric Field Operations

Working Foreman / Lineworker Headcount Jan 2017 - July 2019

Jul-17		Aug-17		Sep-17		Oct-17		Nov-17		Dec-17		Jan-18	
Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker
5	6	6	6	5	6	5	6	5	6	5	6	5	6
3	5	3	5	3	5	2	5	2	5	4	4	4	4
9	8	9	8	9	9	9	9	9	9	9	9	9	9
2	3	2	3	2	3	2	3	2	3	2	3	2	3
4	2	4	3	4	3	4	4	4	4	4	4	4	4
6	6	6	6	6	6	6	6	6	6	6	6	6	6
10	7	10	7	10	9	10	9	10	9	10	9	10	9
10	9	10	9	10	9	10	9	11	9	10	9	11	8
9	8	9	8	9	9	9	9	9	9	9	9	9	9
4	4	4	4	4	5	5	5	5	5	5	5	5	5
5	4	5	4	5	4	5	5	5	5	5	5	5	5
6	6	6	6	5	6	5	5	5	5	5	6	5	6
9	9	10	8	10	10	11	10	11	10	11	10	11	10
0	0	0	0	0	0	0	0	0	0	0	0	0	0
82	77	84	77	82	84	83	85	84	85	85	85	86	84
159		161		166		168		169		170		170	
2	4	2	4	2	4	2	4	2	4	2	4	2	4
	16		16		16		16		16		16		16
181		183		188		190		191		192		192	

NH Electric Field Operations
Working Foreman / Lineworker Headcount Jan 2017 - July 2019

Feb-18		Mar-18		Apr-18		May-18		Jun-18		Jul-18		Aug-18	
Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker
5	6	5	7	4	8	3	7	3	7	3	7	4	7
4	5	5	5	5	5	5	5	5	5	5	5	5	6
9	9	9	8	9	8	9	8	9	8	9	8	9	9
2	3	2	3	2	3	2	3	2	3	2	3	2	3
4	4	4	4	4	4	4	4	4	4	4	4	4	4
6	6	6	6	6	6	6	6	6	6	6	6	6	6
10	8	10	9	9	9	9	9	9	9	10	9	10	10
11	9	11	9	10	9	9	10	10	11	7	10	8	10
9	9	9	9	9	9	9	9	9	9	9	9	9	10
5	5	5	5	5	5	5	5	5	5	5	5	5	5
5	5	5	5	5	4	5	4	5	4	5	5	5	5
6	5	5	5	4	5	4	6	4	6	4	6	4	6
11	10	11	10	11	10	11	11	11	11	11	11	11	16
0	0	0	0	0	0	0	0	0	0	0	0	0	0
87	84	87	85	83	85	81	87	82	88	80	88	82	97
171		172		168		168		170		168		179	
2	4	2	4	2	4	2	4	2	3	4	3	4	6
	16		17		17		16		17		16		16
193		195		191		190		192		191		205	

NH Electric Field Operations
Working Foreman / Lineworker Headcount Jan 2017 - July 2019

Sep-18		Oct-18		Nov-18		Dec-18		Jan-19		Feb-19		Mar-19	
Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker
4	7	4	7	4	8	4	9	4	9	4	7	4	7
5	6	5	6	4	6	5	6	5	6	5	6	5	6
9	9	9	9	9	9	9	11	9	11	9	11	9	11
2	3	2	3	2	3	2	3	2	3	2	3	2	3
4	4	4	4	4	4	4	4	4	4	4	4	4	4
6	6	6	6	6	6	6	6	6	6	6	6	6	6
10	10	10	9	10	9	10	11	10	11	10	11	10	11
8	10	9	10	9	10	9	10	9	10	9	10	9	10
9	8	9	8	9	8	8	8	8	8	8	8	9	8
5	5	5	5	4	5	4	7	5	6	5	5	5	5
5	4	5	4	5	4	5	4	5	4	5	4	4	4
5	6	6	6	6	6	6	5	6	5	6	5	6	5
11	14	11	14	11	14	11	12	11	12	11	12	11	12
0	0			0	0	0	0	0	0	0	0	0	0
83	92	85	91	83	92	83	96	84	95	84	92	84	92
175		176		175		179		179		176		176	
4	6	3	5	3	5	3	5	3	5	3	5	3	5
	21		24		24		25		24		25		23
206		208		207		212		211		209		207	

NH Electric Field Operations
Working Foreman / Lineworker Headcount Jan 2017 - July 2019

Apr-19		May-19		Jun-19		Jul-19	
Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker	Working Foreman	Lineworker
4	7	4	7	4	7	4	7
5	7	5	7	5	7	5	7
9	11	9	11	9	11	8	11
2	3	2	3	2	2	2	2
4	4	4	4	4	4	4	4
6	6	6	6	5	6	4	5
10	11	10	11	10	11	10	11
9	10	9	10	10	10	10	10
9	9	9	9	9	9	9	9
5	5	5	5	4	4	4	4
4	4	4	4	3	4	4	3
6	5	6	5	6	5	6	6
11	12	11	12	11	12	11	12
0	0	0	0	0	0	0	0
84	94	84	94	82	92	81	91
178		178		174		172	
3	7	3	7	3	8	3	8
	22		22		21		21
210		210		206		204	

2019 TD190 CLM Potential Distribution Projects

List all Transformers that have exceeded 85% of TFRAT in last 5 years (or are Projected to exceed 100% TFRAT within 5 Years)

Location	S/S	Transformer	MFG Year	S/S Load Limit (TFRAT)	Max Load (KW)	% of TFRAT	Projected Growth Rate	Projected to Exceed 100% of TFRAT Date	Circuits	Type of Load	CLM Candidate	If not, why?	Entered/Updated By and Date	Comments
Claremont	River Road	46W	1980	7,500	5,390	72%	0.70%	Beyond 2028	1	Industrial	No	N/A	RDJ 5/2019	Transformer rating increased recognizing fans added. (Shown because included in earlier years)
Laconia	Black Brook	11W	1966	10,030	8,760	87%	0.50%	Beyond 2028	2	Mixed	Yes		RDJ 5/2019	Peak occurred on 7/3/14 after an outage on the 310 line supplying the substation. Laconia area study will address loading with Messer St S/S project and Weirs S/S.
Ossipee	Center Ossipee	19W2	1966	5,210	4,510	87%	0.50%	Beyond 2028	1	Residential	No	Residential	RDJ 5/2019	Substation is a 2 transformer substation. Load on station significantly exceeds LTE of a single transformer (8.2MW vs 5.2MW). Preference is for significantly more capacity to back up 19W1 transformer.
Northwood	East Northwood	63W1	1969	5,990	5,190	87%	0.43%	Beyond 2028	1	Residential	No	Residential	RDJ 5/2019	Low cost solution to off-load on step transformers when needed. (RDJ)
Rochester	Portland Street	34W3	1967	5,880	5,110	87%	0.49%	Beyond 2028	1	Mostly residential, some small commercial	No	N/A	RDJ 5/2019	Rochester comprehensive area study. Conversion of 4 kV will alleviate loading.
Loudon	Loudon	31W2	1964	3,710	3,220	87%	0.56%	Beyond 2028	1	Mostly residential, some small commercial	Yes		RDJ 5/2019	Recent loads are below 85% Will investigate when projected to exceed TFRAT within 10 years.
Rochester	Twombley Street	43H	1961	2,750	2,270	83%	0.49%	N/A	1	Mostly residential, some small commercial	No	Replaced with 4kV conversion	RDJ 5/2019	Will be converted to 12kV as part of a comprehensive area project that retires Signal St and addresses loading on Portland St
Rollinsford	Salmon Falls	51H1	1996	1,800	1,660	92%	0.44%	Beyond 2028	1	Residential	Unknown (Residential	Residential	RDJ 5/2019	Will investigate when projected to exceed TFRAT within 10 years.
Nashua	Long Hill	40W1	1966	5,250	4,560	87%	0.46%	Beyond 2028	1	Mix of residential and commercial	Yes		RDJ 5/2019	Will investigate when projected to exceed TFRAT within 10 years.
Milford	Milford 23H3	23H3	1951	1,704	1,460	86%	0.50%	Beyond 2028	1	Residential	Unknown (Residential)	Residential	RDJ 5/2019	Will investigate when projected to exceed TFRAT within 10 years.

Revised 5/2019

Note: Annual Percent increases based on forecast for substation serving subject S/S, based from year 2018 regardless of year of peak.

EVERSOURCE
ENERGY

«CUST_NM» «CUST_NM_2»
«ADRS_TXT_1»
«LOCAL_GOVMT_NM», «ST_CD» «ZIP_CD_NUM»

September , 2015

RE: Account at: «ADRS_TXT_1», «LOCAL_GOVMT_NM» «ST_CD»

Dear Customer:

Service to the electric space heating installed at the address shown above is currently billed under the Heatsmart Rate. This is a reduced rate available to locations with permanently installed electric space heating, along with an approved back-up heating source, that may be subject to brief heating circuit interruptions during periods of high demand.

Eversource is performing a Rate Recertification and compliance review of all locations where Heatsmart meters were installed prior to 2006. Please complete the enclosed form and return it to us in the postage paid envelope at your earliest convenience. If you need assistance, please call the Construction Services Support Center at 1-800-362-7764.

Thank you in advance for your timely response.

Eversource Energy – NH Rates Department

EVERSOURCE
ENERGY

«CUST_NM» «CUST_NM_2»
«MAILING_1»
«MAILING_2» «MAILING_3»

November 7, 2016

RE: Account at: «ADRS_TXT_1», «LOCAL_GOVMT_NM» «ST_CD»

SECOND REQUEST

To date, we have not received a response to the request for information that was sent to this address several months ago. Please take a few minutes to complete the form and return it as soon as possible.

Dear Customer:

Service to the electric space heating installed at the address shown above is currently billed under the Heatsmart Rate. This is a reduced rate available to locations with permanently installed electric space heating, along with an approved back-up heating source, that may be subject to brief heating circuit interruptions during periods of high demand.

Eversource is performing a Rate Recertification and compliance review of all locations where Heatsmart meters were installed prior to 2006. Please complete the enclosed form and return it to us in the postage paid envelope at your earliest convenience. If you need assistance, please call the Construction Services Support Center at 1-800-362-7764.

Thank you in advance for your timely response.

Eversource Energy – NH Rates Department

EVERSOURCE ENERGY

HEATSMART
RATE RECERTIFICATION

Customer Information

Customer Name	Customer Site ID «SERVICEID»		Date
Service Address «ADRS_TXT_1»	City «LOCAL_GOVMT_NM»	State	Zip Code
Mailing Address (if different than above)	City	State	Zip Code
Phone Number	E-mail Address		Installation Date: «INSTALLDATE»

HEATSMART Overview

Eversource's **HEAT**SMART Program provides qualifying customers with a discounted kilowatt-hour rate for their separately metered electric space heating (and cooling if using a heat pump) and electric water heating. To qualify, customers must have permanently installed electric heat and an approved permanently installed back-up heating source sized to adequately heat the area of the premises served by the interruptible electric heat. Approved back-up heating sources are limited to electric thermal storage (ETS) devices as approved by the Company or a wood, wood pellet or coal stove. Wood fired, direct vent fireplaces are acceptable if a manufacturer's spec sheet listing the unit's Btu output rating is submitted with this recertification form and is shown to meet the sizing requirements. Emergency generators are not an eligible backup heating source nor are fossil fueled fireplaces (although they may both be present in the premises). Additionally, fossil fuel based heating systems such as oil, kerosene, propane, or natural gas do not qualify as an approved back-up heating source and cannot be present in the section of the premises to be served by the **HEAT**SMART rate.

In exchange for the lower rate, customers agree to allow Eversource to briefly interrupt service to their heating circuits during periods of high demand for electricity. Eversource can interrupt the separately metered circuits for a total of eight hours in any 24-hour period. However, no single interruption would exceed four hours in duration and the time between consecutive interruptions would be no less than 2 hours. Interruptions will not occur more than five times in a month and no more than 26 times in a year.

Recertification Guidelines

This **HEAT**SMART Recertification form is intended to ensure customer compliance with the requirements of the rate as outlined above. Failure to meet the requirements will result in the unavailability of the **HEAT**SMART rate. Additional information pertaining to **HEAT**SMART and its availability can be found on Eversource's website at www.eversource.com. ("Save Money & Energy" → "Smart Energy Solutions" → "Heating and Cooling".)

For questions pertaining to the **HEAT**SMART Program, please contact Eversource's Construction Services Support Center, at (800) 362-7764 or e-mail nhnewservice@eversource.com.

Heating Information

Primary Electric Heating System (check one)

☐ Resistance Baseboard ☐ Electric Radiant ☐ Air Source Heat Pump ☐ Geothermal/Ground Source Heat Pump ☐ Electric Heat has been Removed

Back-up Heating Source (check one)

☐ Wood Stove ☐ Wood Pellet Stove ☐ Wood-fired Qualifying Fireplace ☐ Coal Stove ☐ Electric Thermal Storage ☐ None

Is a dedicated electric hot water tank connected to the **HEAT**SMART panel/meter? (Tank must be 40 gallons or more to be eligible.)

☐ Yes ☐ No

Customer Approval

I have read and understand the Recertification Guidelines for **HEAT**SMART and accept full responsibility for compliance

Date:	
Customer Name (print)	Customer Signature

9/2015

System	Div.	AWC	Parent 1	Parent 2	Project #	Project Title	In-service Date	2019 ($1,000)	Cumulative ($1,000)	Description	Justification
ELECT OPS	All		New Customer	Customer Driven	DN9R	DN9R - NEW/EXISTING CUSTOMERS - PSNH		8,000	8,000		
ELECT OPS	All		New Customer	Customer Driven	DV9R	SERVICES - PSNH		3,250	11,250		
ELECT OPS	All		Basic Business	Line Relocations/Act of Public Authority	C03CTV	CABLE TV PROJECTS ANNUAL		500	11,750		
ELECT OPS	E		Basic Business	Line Relocations/Act of Public Authority	A18E23	Rochester Comcast Make Ready		536	12,286		
ELECT OPS	All		Basic Business	Line Relocations/Act of Public Authority	C03DOT	NHDOT PROJECT ANNUAL		1,850	14,136		
ELECT OPS	W	31	Basic Business	Line Relocations/Act of Public Authority	A18W22	Peterborough Roadway and Bridge		150	14,286		
ELECT OPS	All		Basic Business	3rd Party/Joint Owner Work	C03TEL	TELEPHONE PROJECTS ANNUAL		200	14,486		
ELECT OPS	All		Basic Business	Environmental	CO1PCB	PCB Transformer Replacements		75	14,561		
ELECT OPS	All		Basic Business	3rd Party/Joint Owner Work	C01SPA01	Joint Pole		200	14,761		
ELECT OPS	All		Basic Business	Lighting	DA9R	NON-ROADWAY LIGHTING		400	15,161		
ELECT OPS	All		Basic Business	Line Relocations/Act of Public Authority	DH9R	LINE RELOCATIONS		1,000	16,161		
ELECT OPS	All		Basic Business	Emergent Equipment Failures - Line	DQ9R	DQ		9,500	25,661		
ELECT OPS	All		Basic Business	Emergent Equipment Failures - Line	DS9RE	ROW DQ		1,200	26,861		
ELECT OPS	All		Basic Business	Basic Business - Other	GF9R	GEN OFF FURN/EQUIP - ED		100	26,961		
ELECT OPS	All		Basic Business	Capital Tool Purchases	GM9R	Tools and Equipment- 1250		160	27,121		
ELECT OPS	All		Basic Business	Capital Tool Purchases	GT9R	Tools and Equipment- Troubleshooters		560	27,681		
ELECT OPS	All		Basic Business	Capital Tool Purchases	GX9R	TOOLS/EQUIPMENT CONSTRUCTION - E		1,100	28,781		
ELECT OPS	All		Basic Business	Lighting	HPS9R	HPS ADDS/CHNGS		120	28,901		
ELECT OPS	All		Basic Business	Insurance Claim/Keep Cost	INSOH9R	Claims OH, UG, DB		600	29,501		
ELECT OPS	All		Basic Business	Emergent Equipment Failures - Line	MINOR9R	MINOR STORM WORK - VARIOUS AWC'S		130	29,631		
ELECT OPS	All		Basic Business	Emergent Equipment Failures - Line	NHLC03	Line Contractors		300	29,931		
ELECT OPS	All		Basic Business	Emergent Equipment Failures - Line	STORMCAP	STORM CAPITALIZATION		600	30,531		
Eng. Annual	All		Basic Business	Pre-Cap Line Transformers	DT7P	Transformer and Regulators Annual		10,190	40,721		
Eng. Annual	All		Basic Business	Capital Tool Purchases	GE9R	Tools and Equipment		75	40,796		
	All		Basic Business	Grid Mod	A19X28	Advanced Load Flow Software		500	41,296	Grid Mod group asking for $500k base budget item	
	All		Basic Business	Grid Mod	A19X29	NH DMS Pilot Phase 2		500	41,796	Grid Mod group asking for $500k base budget item	
ROW	All		Reliability	Reliability - Distribution Line	DL9R	Distribution ROW Annual	12/31/xx	5,000	46,796		
S/S	All		Reliability	Substation Reliability	DS9RD	Dist. S/S Annual - DM	12/31/xx	750	47,546		
DIST LINES	All		Reliability	Network Reliability	A19X01	Replace degraded manholes	12/01/xx	200	47,746	Replace Manholes in poor condition.	
DIST LINES	**All**		Reliability	Distribution Line Reliability	DR9R	Reliability Improvements Annual	12/31/XX	2,000	49,746	Misc. jobs under $100k to improve reliability. Typically involves adding protective devices, replacing aged or poor performing equipment, etc.	
DIST LINES	All		Reliability	Distribution Line Reliability	A07X45	Roadside Reject Pole Replacement	12/31/XX	2,500	52,246	Poles are inspected, if rotten with insufficient remaining strength, then replaced or reinforced.	
DIST LINES	E	61	Reliability	4 kV Conversions	A17E09	Rochester 4kV Conversion	12/31/20	793	53,039	Build tie between Twombley and Portland Street	
DIST LINES	E	63	Reliability	4 kV Conversions	A17E01	Rye Area 4kV Conversion	12/31/20	800	53,839	Convert Rye area to 12 kV and eliminate Foyes Corner 4 kV	
DIST LINES	W	31	Reliability	Distribution Line Reliability	A18W17	Emerald St Distribution Line Work	12/1/19	500	54,339	Associated with Emerald St S/S project.	
DIST LINES	W	31	Reliability	Distribution Line Reliability	A19W03	Streetside Reconstruction/Hardening - Replace open wire with Spacer cable Route 63 Hinsdale (Part 1)	12/1/19	1,000	55,339	3139X Main Line from Chestnut Hill S/S north	
DIST LINES	S	23	Reliability	Distribution Line Reliability	A19S04	Streetside Reconstruction/Hardening - Reconductor #6 copper at 19.9 kV Fordway Extension Derry	12/1/19	350	55,689	Reconductor #6 copper at 19.9 kV Fordway Extension Derry	

System	Div.	AWC	Parent 1	Parent 2	Project #	Project Title	In-service Date	2019 ($1,000)	Cumulative ($1,000)	Description	Justification
DIST LINES	C	12	Reliability	Distribution Line Reliability	A19C05	Streetside Reconstruction/Hardening - Reconductor copper St Anselm Drive Manchester	12/1/19	210	55,899	Safety issue - will do south to URD development to eliminate step up transformer	
DIST LINES	S	21	Reliability	Distribution Line Reliability	A19S06	Streetside Reconstruction/Hardening - Replace #2 copper Route 13 Amherst and Mont Vernon	12/1/19	893	56,792	1.6 miles of #2 to be replaced with 477 spacer cable. Provides a more reliable feed into Mont Vernon	
DIST LINES	E	63	Reliability	Distribution Line Reliability	A19E07	Downtown Portsmouth UG System Improvement	12/31/XX	100	56,892	Continuing project to upgrade the underground system in downtown Portsmouth includes expansion of the system as the City is redeveloped	
DIST LINES	S		Reliability	Distribution Line Reliability	A19S08	CAIDI Improvement - Relocate 3168X Bridge St S/S	12/31/XX	517	57,409	Relocate section of 3168X from river crossing and railroad ROW to improve ability to repair.	
DIST LINES	N	76	Reliability	Distribution Line Reliability	A19N09	CAIDI Improvement - Relocate 1W1 Main Line onto Route 3	12/31/XX	260	57,669	Project to improve access/ability to repair.	
DIST LINES	W	31	Reliability	Distribution Line Reliability	A19W10	CAIDI Improvement - Relocate feed to Hinsdale Wastewater Treatment Plant	12/31/XX	250	57,919	Project to improve access/ability to repair.	
DIST LINES	W	31	Reliability	Network Reliability	A08W49	Replace Keene Downtown URD with Surface Mounted Equipment	12/1/19	800	58,719	This project will remove the underground transformers and switch gear in the Keene downtown underground. Surface mounted equipment will be installed to refeed customer.	This project is in progress. Eversource has been working closely with the City of Keene with regard to permitting, equipment locating, and communication within the community.
DIST LINES	E	61	Reliability	Distribution Line Reliability	A19E11	Circuit Ties - Wakefield 362 to 3157	12/31/XX	2,700	61,419		
DIST LINES	N	41	Reliability	Distribution Line Reliability	A19N12	Circuit Ties - Laconia 310 to 345	12/31/XX	4,100	65,519		
DIST LINES	All		Reliability	URD/DB Cable Improvements	A18X01	Direct Buried Cable Replacement	12/31/XX	700	66,219	Replace poor performing direct buried cable with cable in conduit and replace livefront transformers.	2019: Maple Hill Acres in Derry , phase 2 of 3
ROW	All		Reliability	Distribution Line Reliability	A19X20	Replace Lattice Steel Towers	12/31/xx	250	66,469	Replace rusted steel towers with steel poles on various 34.5 KV lines in ROW.	Replace rusted steel towers with wood structures on various 34.5 KV lines in ROW.
ROW			Reliability	Distribution Line Reliability	A18X28	ROW Hardening/Reconductoring	12/31/xx	1,510	67,979	Rebuild 317 (14 mi), reconductor 314 (2 mi), 3155 (2.4 mi), 324 (1 mi), 334 (1 mi), 3614 (2.25 mi), 393 (1 mi), 328 (3.5 mi)	Approx $650k/mi for rebuild with steel poles and spacer cable means $18M for listed projects
ROW	S	21	Reliability	Distribution Line Reliability	A19S27	Relocate 314 Line around Heron Pond	12/1/19	600	68,579	Replace structures located in Heron Pond due to poor condition.	
ROW	S	12	Reliability	Distribution Line Reliability	A17C26	328 Line - Reconductor 266 ACSR (Goffstown)	6/1/19	3,618	72,197	Will need $2500k funding in 2019 Reconductor 3.55 miles of 266 ACSR with 477 ACSR from p.328/6 to p.328/55.	Reliability - line limitation with SCADA switching Contingency: Weare 3271 including 3194
S/S	W	31	Reliability	Substation Reliability	A14W01	Keene S/S - Rebuild 115-12.47 kV S/S with 30 MVA Transformer and associated switchgear.	6/1/20	8,221	80,418	* Rebuild Keene Substation equipment with two new 30 MVA transformers and associated switchgear. * (The existing TB3 transformer (22.4 MVA) at Keene will remain)	* Aging infrastructure * The available fault current exceeds the interrupting rating of two transformer breakers and the switchgear. * The majority of the equipment at Keene Substation is old and obsolete.
S/S	N	41	Reliability	Substation Reliability	A17N02	Messer St - Replace TB70	6/1/19	2,653	83,071	Replace TB70. The 4.16 kV load has been converted and offloaded to 12.47 kV	Replace 1969 5250kva TB70 with 10/12.5MVA
S/S	N		Reliability	Substation Reliability	A16N02	Second transformer at Lost Nation S/S	6/2/19	1,327	84,398	Add second transformer (replacing failed unit that was removed in 2003). Replace existing circuit switcher, address P&C and other deficiencies.	Sale of Jet and GSU that acts as ground source for loss of single transformer at Lost Nation requires addition of second transformer that failed and was removed in 2003.
S/S	S	21	Reliability	Substation Reliability	A17S03	Nashua - Millyard S/S Replacement	12/31/21	1,336	85,734	See Millyard Study	1953 vintage - condemned getaway poles. One direct buried getaway cable has failed and had to be replaced. Getaway cables and CTs both limit loading to 400 amps which limits ability to utilize existing circuit ties.
S/S	E	61	Reliability	Substation Reliability	A17E05	Twombley S/S - Rebuild at 12.47 kV with 12.5 MVA	6/1/20	1,500	87,234	Rebuild Twombly with 10/12.5 MVA, change tap on Portland St to 12kV , retire signal Street. Convert the 4.16 kV downtown to 12.47 kV to allow for load growth. Create ties with other 12.47 kV circuits to allow for contingency operation.	The equipment at Portland St., Signal St., and Twombley St. Substations, not including TB341, is an average of 56 years old. The 61 year old transformer, 28H1 at Signal St., is the sister unit of failed transformers at Franklin and Community Street Substations. Potential failure of the transformer at Signal St. Substation is the biggest concern. convert the downtown area to 12.47 kV and increase circuit ties with existing 12.47 kV circuits. This solution allows for future growth while optimizing the capacity for contingency switching.
S/S	N		Reliability	Obsolete Equipment	A17N18	Laconia SS equipment replacement	06/01/19	1,531	88,765	Replaces OCBs and Cap switcher	
S/S	W		Reliability	Obsolete Equipment	A17W19	North Road SS equipment replacement	06/01/19	384	89,149	Replace a circuit switcher.	
S/S	C		Reliability	Obsolete Equipment	A16C10	Jackman S/S Replace obsolete Equip	06/01/19	23	89,172	Carry-over from Jackman obsolescense project.	

System	Div.	AWC	Parent 1	Parent 2	Project #	Project Title	In-service Date	2019 ($1,000)	Cumulative ($1,000)	Description	Justification
S/S	E	63	Reliability	Substation Reliability	A08N10	Portsmouth S/S - Add a second 115-34.5 kV 44.8 MVA transformer	6/1/20	4,689	93,861	A second 115 – 34.5 kV, 44.8 MVA transformer will be added to Portsmouth Substation. The existing substation has room for a second transformer. The project will require an expansion of the 115kV bus at Portsmouth S/S. This will occur as part of the F107 project. The 34.5 kV bus work will include adding a SCADA controlled 34.5 kV bus tie breaker and a new line position. The installation of two 5.4 MVAR capacitor banks (one on each bus) will be evaluated and installed as appropriate.	* Equipment overload * The Portsmouth substation transformer (TB156) is expected to operate at 96.6% of its TFRAT rating (112.9% nameplate) in 2019. (Identified in the 10 year planning study.)
S/S	E	63	Reliability	Obsolete Equipment	A17E20	Ocean Road OCB replacement	06/01/18	900	94,761		
	C		Reliability	Obsolete Equipment	A18C02	Bedford SS PLC Automation Scheme Replacement - Funded from A16S01	6/1/19	989	95,750	See A16S01	
S/S	All		Reliability	Obsolete Equipment	DS9RS	Substation Annual - Substation	12/31/XX	1000	96,750	The Substation Engineering Annual supports capital projects up to $50,000 and typically include obsolete equipment replacements, wood structure replacements, regulator clearances	Prevent failure of aged and non-standard installations of equipment to impact system reliability.
	E		Reliability	Substation Reliability	A18E04	Dover S/S Rebuild	12/31/20	1,863	98,613	Rebuild Dover S/S with two 62.5 MVA fully rated transformers, bus tie breaker, new control house.	Asset condition of control house, does not meet SYSPLAN 010 planning criteria.
			Reliability	Substation Reliability	A18X26	Purchase 14 MVA 34x46 to 12 kV Mobile Substation	5/31/18	1,500	100,113		
S/S	W	31	Reliability	Substation Reliability	A18W06	Monadnock SS - Replace Transformer TB40		3,500	103,613	Replace 20 MVA transformer at Monadnock with 44.8 MVA unit. 2018 ENGINEERING Estimated $4M total	Substandard substation design, does not meet SYSPLAN 010 planning criteria.
S/S	All		Reliability	Obsolete Equipment	A19X36	34.5 KV Substation OCB and Ancillary Equipment Replacement Program	12/1/XX	1,000	104,613	Program to replace oil circuit breakers in substations (97 remaining as of end of 2017).	
S/S	S	23	Reliability	Obsolete Equipment	A16S01	PLC Automation Scheme Replacement - 2018 funding moved to Pine Hill ($600) and Bedford ($400)	12/31/xx	964	105,577	Replace two GE-Fanuc PLCs with SEL-Axion substation I/O, replacement of both SEL-2030s with SEL-3530 RTACs and replacement of the PC based HMI with SEL-2523 annunciator panels. Also, install SEL-Axion substation I/O in each control/relay cabinet to replace all ESCC metering, status and control functions now performed by the protective relays. This new automation scheme will not rely on the protective relays for any ESCC metering data, digital data or control points.	The original data maps were developed using specific SEL relay firmware which is now classified as legacy. A failed relay must be sent back to the factory for repair because a new relay cannot be retrofit with the old firmware. The old firmware is not IEC 61850 compliant. The new design results in the ability to use up-to-date relays and firmware. The data maps and parsing of data was developed by EPRO (now TRC). Eversource employees are not familiar with this programming and depend upon one vendor (TRC) to make major modifications. SCADA control of breakers is thru relays and a relay failure will cause loss of supervisory control. Transformer alarms are passed thru the 387E numerical relays. Maintenance or failure of this relay causes a loss of transformer SCADA alarms. The PLC contacts are rated for 24 -110 VDC. The station battery is rated at 125 VDC. This has resulted in PLC contacts being welded together. The HMI computer is using a Windows 95 operating system.
	All		Reliability	Obsolete Equipment	A18X08	Electromechanical Relay Replacement Feeder electromechanical, Xfmr overcurrent, ABB Diff Relays	12/31/2018	1,000	106,577	Program to address obsolete relays.	
S/S			Reliability	Obsolete Equipment	UB0830	Capacitor Switch Replacements	12/31/XX	800	107,377	The program was established in 2008. It is now expected to continue through 2025. It supports 1-2 replacements per budget year.	
S/S			Reliability	Obsolete Equipment	A17N22	Beebe River Capacitor Switch Replacements	12/31/XX	661	108,038		
S/S	W	32	Reliability	Substation Reliability	A16W01	CVEC Substation upgrades	12/31/19	100	108,138	Generally ground grid and fence upgrades.	
S/S	C	11	Reliability	Substation Reliability	A16C08	Brook St S/S - 13TR1 Replacement (Switchgear)	12/31/20	200	108,338	Replace the Westinghouse 13TR1 Switchgear with new 15kV metalclad switchgear. The scope will also include upgrading the feeder protection on both 13TR1 and 13TR2 line ups.	
S/S			Reliability	Substation Reliability	A19E30	Retire Foyes Corner S/S 4kV	7/1/19	100	108,438	Per Rye Area Study	
S/S			Reliability	Substation Reliability	A17C04	Greggs S/S Removal	7/1/19	1,000	109,438	Retirement of Greggs S/S	
S/S			Reliability	Substation Reliability	A19X22	Substation Animal Protection Equipment Program		500	109,938	Individual program releases to be managed by Substation Engineering. Each release/location will have its own project number.	

System	Div.	AWC	Parent 1	Parent 2	Project #	Project Title	In-service Date	2019 ($1,000)	Cumulative ($1,000)	Description	Justification
S/S			Distribution Automation		A19XDA	Distribution Automation - Substation	12/31/xx	1,000	110,938	Add SCADA to non-bulk substations	
			Distribution Automation		A19TDA	Distribution Automation - Telecom	12/31/xx	100	111,038	Install base station radios to provide coverage for Distribution Automation devices	
DIST LINES			Distribution Automation		A19DA	Distribution Automation - Pole Top	12/31/xx	16,743	127,781		
DIST LINES			Distribution Automation		A19LS	Distribution Automation - Line Sensors	12/31/xx	180	127,961		
DIST LINES	W	31	Regulatory Commitments	Regulatory Commitments - Other	A19S23	Miller State Park/Pack Monadnock		1,050	129,011	Rebuild/relocate line feeding the top of Pack Monadnock/Miller State Park	
S/S	C		Regulatory Commitments	Regulatory Commitments - Other	A18C07	Amoskeag - Eddy S/S Control House	12/31/20	523	129,534	Project is the result of the generation divestiture.	
S/S			Regulatory Commitments	Regulatory Commitments - Other	A16X01	ESCC Control of Generation	12/31/19	51	129,585	Project is the result of the generation divestiture.	
DIST LINES	All		Regulatory Commitments	Regulatory Commitments - Other	A19X24	NESC Capital Repairs	12/31/XX	100	129,685	Project to address NESC clearance violations.	
S/S	All		Regulatory Commitments	Regulatory Commitments - Other	6DCIP	NH Avigilon Intrusion Detection	12/31/17	109	129,794	Update security at 9 shared substations to meet NERC CIP Standards v5 by April 2017	The purpose of the NERC CIP v5 set of requirements is to provide electronic and physical security to Bulk Electric System (BES) Cyber Assets that could impact the reliability of the BES if compromised.
DIST LINES	All	All	Peak Load	Distribution Line Capacity	DK9R	Maintain Voltage - PSNH	12/1/xx	700	130,494	Annual to address voltage violations.	
DIST LINES	C	12	Peak Load	Distribution Line Capacity	A19C25	Reconductor Bedford Road, 360X7	12/31/19	300	130,794	Reconductor 2800 feet of single phase 1/0 ACSR with three phase spacer cable along Bedford Road to split load between phases	Main line load imbalance. Parallel 500 kVA steps reached 950 kVA in July 2018.
DIST LINES	E	61	Peak Load	Distribution Line Capacity	A19E26	Convert Four Rod Road in Rochester	12/31/19	160	130,954	Install 1/0 34 kV spacer cable along Four Rod Road in Rochester and convert to 34 kV.	Step transformer reached 120% nameplate in summer of 2018. Potental for tie along Sampson Rd to provide alternate source.
S/S	W		Peak Load	Substation Capacity	A17W06	River Road S/S	12/1/19	2,000	132,954	2-2.5 MW being added to Industrial Park by 2018. Need confirmation and area study.	
S/S	E		Peak Load	Substation Capacity	A18N05	Pemi S/S - Replace 20 MVA transformer with 62.5	12/1/19	3,271	136,225	Basecase overload of transformer.	
								136,225			

NEW HAMPSHIRE – SYSTEM ENGINEERING
SYSTEM PLANNING & STRATEGY

Webster Substation Review

June 24, 2019

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Executive Summary

This study looks at the future of Webster Substation and possible replacement substations in the Franklin area. It is driven by obsolescence and equipment overload at Webster Substation. The transformer, TB54, is projected to exceed nameplate rating in 2015. [redacted] the solution needs to maintain some transformation in the immediate area to support the extensive 34.5 kV system. The system currently fed by Webster Substation feeds over 7,000 Eversource customers and over 3,500 New Hampshire Electric Coop (NHEC) customers.

The largest limitation, with utilizing the existing Webster Substation property, is the placement of the NHEC Webster Substation. The NHEC substation is located in the middle of Eversource's property and makes it difficult to expand the existing Webster Substation. There is additional property available for Eversource to develop on the other side of NHEC's substation.

It is recommended that Eversource replace the three existing bulk substation transformers (two 20 MVA and one 15 MVA) at Webster Substation with two 115 – 34.5 kV, 44.8 MVA transformers. The new bulk transformers will be located within the existing Webster Substation. In a separate enclosure, on the other side of NHEC Webster Substation, a 34.5 kV bus and switching station will be constructed. The separate 34.5 kV will be designated as Daniel Substation. The finished project will increase capacity, eliminate obsolesce issues, and fit within limited land constraints, while maintaining the existing transmission assets. The new substation site will also allow for future expansion by supplying additional breaker positions. This solution is the best project to address loading issues in an area where transformation is critical.

Respectfully submitted:

[redacted]

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I. Introduction

This review was initiated to address transformer overloads identified in the 10 Year Study. The existing system configuration, equipment limitations, system loading and area load growth rate are used to assess future system requirements. The objective of this study is to develop recommendations that address the long term loading requirements and equipment obsolescence in the Webster Substation area.

II. Study Background

The electric system is primarily 34.5 kV in the Webster Substation area, making it is necessary for this study to focus on a 34.5kV transformation solution. This report summarizes the best solution for the electrical system need at Webster Substation, developed in the 10 Year Study. Webster Substation has been identified in the past as an area with need for improvement. [redacted]

III. System Analysis

Area Problems & Limitations

1. **Natural Load Growth** – A 1.5 % natural load growth is expected for the area fed by Webster Substation. This will cause bulk substation transformer, TB54, to reach its TFRAT (transformer rating) within five years. The "TFRAT" is a rating, above the nameplate, that assumes no additional loss of life, which is calculated based on its respective load curve.
2. **New Large Customers** – Two large customers are expected to come online within the next five years, significantly increasing substation loading. [redacted] is expected to add an additional [redacted] of load within the next year to the 3548 line, fed from Webster Substation. Also, the Northern Pass Converter Station is expected to add another 1 MW of station service load to the 3548 line by 2019.
3. **Geography** – The existing Webster Substation is located in a desirable location to transform power to the local distribution circuits. [redacted]

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Substation Problems & Limitations

1. **Obsolescence** – The three transformers at Webster Substation are all in excess of 60 years old. There are also four oil circuit breakers that are older than 60 years. The age of all bulk transformers and circuit breakers are shown below in Table 3.1. Based on a useful life expectancy of 55 years, about 80% of the distribution equipment at Webster Substation is obsolete. Potential failure of a transformer due to age and loading is the biggest concern.
2. **Crowding** – [redacted] there is little room at Webster Substation for construction and improvement. Significant outages would be necessary to facilitate construction at the site. For more detail, please see Appendix C for a one-line diagram of Webster Substation.
3. **Outage Coordination** – [redacted] The 34.5 kV bus is a shared bus between all three bulk transformers, requiring a complete 34.5 kV station outage for certain work.

SUBSTATION	EQUIPMENT	POSITION	MANUFACTURER	YEAR	AGE
Webster	LTC Transformer (20 MVA)	TB37	Westinghouse	1951	64
	LTC Transformer (16 MVA)	TB54	Westinghouse	1954	61
	LTC Transformer (20 MVA)	TB96	Westinghouse	1955	60
	Oil Circuit Breaker	TB37	General Electric	1949	66
	Oil Circuit Breaker	TB54	General Electric	1954	61
	Oil Circuit Breaker	TB96	General Electric	1955	60
	Oil Circuit Breaker	3216	General Electric	1950	65
	SF6 Circuit Breaker	3548	Siemens	2004	11
	SF6 Circuit Breaker	BT40	Siemens	2003	12

Table 3.1 - Equipment ages at Webster Substation

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Transformer Loading

Base equipment loading was examined for all 34.5 kV equipment at Webster Substation. The 2015 Summer Forecast peak load was used to model the distribution system. The 2015 forecasted load was then brought forward to 2025 at a load growth rate of 1.50 % for the first five years and then 1.25% for the latter five. These values were recorded in Table 3.2 below, which shows the result of the projected 2015 and 2025 loading on the substation equipment, if the current configurations were to remain the same.

SUBSTATION	EQUIPMENT	2015 Forecast	2025 Forecast	NAMEPLATE RATING	TFRAT RATING
Webster	LTC Transformer – TB37	15.2 MVA	17.7 MVA	20.0 MVA	25.0 MVA
	LTC Transformer – TB54	15.4 MVA	17.9 MVA	15.0 MVA	17.0 MVA
	LTC Transformer – TB96	15.3 MVA	17.8 MVA	20.0 MVA	25.0 MVA
	3216 Getaway – 477 ACSR 26/7	15.5 MVA	17.4 MVA	38.8 MVA	48.7 MVA
	3548 Getaway – 477 ACSR 26/7	29.9 MVA	34.1 MVA	38.8 MVA	48.7 MVA

Table 3.2 – Results of a loading analysis for 34.5 kV Webster Substation equipment (modeled at 2015 and 2025 load levels)

The results of the equipment loading analysis show TB54 over both nameplate and TFRAT ratings. The nameplate rating is exceeded in 2015, while the TFRAT rating is exceeded in 2018. Due to the impedance similarity between the three bulk transformers, the units tend to share the load equally, even though they have different MVA ratings. There have been no circuit reconfigurations or planned construction included with these loading values. No other equipment has considerable projected overloads by 2024.

Loadflow Analysis

A loadflow model was developed in accordance with the 10 Year Study. Included with the regular load growth, were two large spot loads that will be impacting Webster Substation: [redacted] and the Northern Pass Converter Station.

Modeling the system base case for 2025, it was determined that additional transformation is needed to meet TFRAT requirements at Webster Substation. There were no voltage or line limit violations found for the Webster area at any point during the study.

Eversource policy ED-3002 identifies that distribution system contingencies shall be studied at peak load times for loss of 34.5 kV line breakers and loss of distribution power transformers. The contingent loss of a 34.5 kV line breaker or transformer was analyzed. There were no contingency scenarios available that would violate system design criteria. For more detail, Appendix E provides a one line of the 34.5 kV system involving Webster Substation.

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Webster Substation Transmission Line Map

[redacted]

Figure 3.3 – Aerial view of Webster Substation and associated transmission lines.

Line Construction Restrictions

New Hampshire Electric Coop (NHEC) Webster Substation

The NHEC Webster Substation lies between the existing Webster Substation and the rest of the available property at the site. This substation restricts the ability to expand the existing Webster Substation or add new lines. This does not prevent construction from happening elsewhere on the property; it only increases the difficulty and requires additional steps to be taken when planning. The property is located between Route 11, Webster Lake Rd. and Carr St. in Franklin, NH. See Appendix D for additional property information.

Figure 3.4 – Location of the NHEC Webster Substation.

IV. Solution Options

Five solutions to address the Webster Substation transformer overload were developed. These options were reviewed for the best solution in terms of cost, construction, and future use. Project estimates are included in Appendix A. There are no other substation overloads in the area that a similar project could address. Figure 4.1 below helps emphasize the [redacted] and its assets in relation to the surrounding transmission lines and substations.

[redacted]

Figure 4.1 – Webster Substation position in relation to other 115 and 34.5 kV lines. Black lines are 115 kV while red are 34.5 kV.

Option 1: Rebuild the Existing Webster Substation with two 44.8 MVA transformers

Remove the three existing bulk transformers from Webster Substation and replace them with two 115 – 34.5 kV, 44.8 MVA transformers. Perform 34.5 kV bus work in order to facilitate the new transformer installation.

Target
- Addresses all obsolescence and loading issues at Webster Substation.

Positives
- Requires minimal footprint.
- Immediately resolves all loading and obsolescence issues at Webster Substation.
- Has the least disturbance for abutters.
- Minimal line work would be required.

Negatives
- Does not allow for the existing equipment to remain in service during construction. A mobile transformer would be necessary to facilitate construction.
- Does not allow any room for future expansion.
- Creates difficulty when trying to add future breaker positions or bus ties.

Conclusion
- This is a feasible option that will solve the obsolescence and loading problems, but does not allow for any expansion at the site.

Option 2: Construct a New Substation on the Existing Property and Replace the Bulk Transformers with Two 44.8 MVA Transformers (Daniel Substation)

A new substation will be constructed on the existing property, adjacent to the current Webster and NHEC Webster Substations. The existing Webster Substation will be utilized as a transmission yard with two new 115 – 34.5 kV, 44.8 MVA transformers. A 34.5 kV bus and switching yard will be added at the new site, Daniel substation, and the old bulk substation transformers will be retired.

Target
- Addresses all obsolescence and loading issues at Webster Substation.

Positives
- Utilizes existing property.
- Immediately resolves all loading and obsolescence issues at Webster Substation.
- Minimal line work would be required.
- Allows for construction with existing equipment remaining in service.
- Allows for future expansion at the existing Webster Substation and the newly constructed substation.

Negatives
- Requires construction around the NHEC Webster Substation.
- Costs slightly more up-front than the one transformer option. (Option 3)

Conclusion
- This would be the ideal solution at a moderate cost due to the increased flexibility for both substations located on the property.

Option 3: Construct a New Substation on the Existing Property with One 44.8 MVA Transformer Now and One 44.8 MVA Transformer Later (Daniel Substation)

A new substation will be constructed on the existing property, adjacent to the current Webster and NHEC Webster Substations. Initially, one 115 – 34.5 kV, 44.8 MVA transformer will be added at the new site and TB54 will be retired. Eventually, the existing Webster Substation will be utilized as a transmission yard when a second 115 – 34.5 kV, 44.8 MVA transformer is added to the new site and TB37 and TB54 are retired.

Target

- Addresses all obsolescence and loading issues at Webster Substation.

Positives

- Utilizes existing property.
- Immediately resolves all loading issues but not obsolescence issues at Webster Substation.
- Minimal line work would be required.
- Allows for construction with existing equipment remaining in service.
- Eventually allows for future expansion at the existing Webster Substation and allows for expansion at the new substation.

Negatives

- Does not resolve all obsolescence issues immediately.
- Requires construction around the NHEC Webster Substation.
- Costs significantly more to add a second transformer later and construct 115 kV feeds.

Conclusion

- This is a feasible option but will require significantly more money to construct 115 kV lines and add a second transformer in the future.

Option 4: Methods of Load Curtailment Including Battery Storage, Distributed Generation, or Conservation and Load Management

Utilize conservation and load management, battery storage, and/or distributed generation to reduce the loading on Webster Substation and postpone capital spending.

Target

- Addresses only loading issues at Webster Substation.

Positives

- Helps to postpone a capital investment and reduces the amount of spending needed in the short term.

Negatives

- Would not be a long term solution and would only delay spending.
- Does not resolve any obsolescence issues.
- Does not solve the overcrowded substation problem to allow for future construction.

Conclusion

- This is not a feasible option since it only temporarily addresses loading issues. Obsolescence issues are not addressed and loading issues would need to be fixed eventually.

Option 5: Construct a New 115 – 34.5 kV Substation at a New Location

Find an entirely new location to build a new 115 – 34.5 kV substation and create the infrastructure to feed the existing 34.5 kV system.

Target
- Addresses all obsolescence and loading issues at Webster Substation.

Positives
- Immediately resolves all loading and obsolescence issues at Webster Substation.
- Allows for construction with existing equipment remaining in service.
- Allows for future transmission expansion at the existing Webster Substation.

Negatives
- Does not utilize existing property.
- Extensive line work would be required.
- Requires acquisition of new property, in a convenient location, to feed the 34.5 kV system.
- Would not be as operationally efficient as the Webster Substation property location.

Conclusion
- This is a not a feasible option, since it requires the acquisition of new property, when there is already property owned in a prime location to feed the 34.5 kV system.

V. Recommendations

New Hampshire's System Planning and Strategy has studied several options and has evaluated them based on feasibility, plausibility, reliability, cost, and system operational flexibility (See Section IV and Appendix B). The Webster Substation area solution incorporates design standards and justifications from the Distribution System Engineering Manual, as well as Eversource policy ED-3002. The resulting design will be reliable and allow for future growth as the economy recovers.

Based on the information contained in this report, it is recommended that Eversource select Option 2: Construct a New Substation on the Existing Property and Replace the Bulk Transformers with Two 44.8 MVA Transformers (Daniel Substation) – $8,800,000. Included with Option 2 is the following:

1. Construct a new substation on the existing property, next to Webster Substation.
2. Install two 115 – 34.5 kV, 44.8 MVA transformers in the existing Webster Substation.
3. Install a 34.5 kV bus and switching yard in a new substation (Daniel Substation) on the existing property with five 34.5 kV breakers.
4. Allow for a fourth position in which to add a future 34.5 kV breaker.
5. Retire the existing three bulk transformers at Webster Substation (TB37, TB54, and TB96)
6. Provide two 34.5 kV feeds from the existing Webster Substation to the 34.5 kV bus at Daniel Substation.
7. Utilize the third empty breaker position at Webster Substation for a mobile substation connection.

Appendix A: Distribution Estimates for Projects

Option 1: Rebuild the Existing Webster Substation with two 44.8 MVA transformers
$8,500,000
Estimate includes:

- Site development and new foundations.
- Installation of two 44.8 MVA, 115 – 34.5 kV transformers and two line breakers with a position to add a third.
- Protection and Control upgrades at the existing station.

Option 2: Construct a New Substation on the Existing Property and Replace the Bulk Transformers with Two 44.8 MVA Transformers (Daniel Substation)
$8,800,000
Estimate Includes:

- Site development and new foundations.
- Installation of two 44.8 MVA, 115 – 34.5 kV transformers.
- 34.5 kV lines from the bulk transformers at Webster Substation to the 34.5 kV switching yard at Daniel Substation.
- Installation of five breakers at Daniel Substation (three feeder breakers) with a position to add a sixth.
- Retirement of the existing, three bulk substation transformers.

Option 3: Construct a New Substation on the Existing Property with One 44.8 MVA Transformer Now and One 44.8 MVA Transformer Later (Daniel Substation)
$13,400,000
Estimate includes:

- Site development and new foundations.
- Construction of an open-air 115 – 34.5 kV substation in two stages. One 44.8 MVA transformer added new and one 44.8 MVA transformer added later.
- Transmission line work to feed across the property from Webster Substation to the new transformers at Daniel Substation.
- Retirement of transformer TB54 now, later retiring TB37 and TB96.

Option 4: Methods of Load Curtailment Including Battery Storage, Distributed Generation, or Conservation and Load Management
Not a feasible solution.

Option 5: Construct a New 115 – 34.5 kV Substation at a New Location
Not a feasible solution.

Appendix B: Decision Matrix for Proposed Work

	Weight	RATING 4-5 Superior, 2-3 = Adequate, 0-1 = Inferior		
		Option 1: Existing Site w/ 2 Transformers	**Option 2:** New Site @ Webster w/ 2 Transformers	**Option 3:** New Site @ Webster w/ 1 Transformer Later
Addresses ED-3002 Design Criteria	8	3	3	3
Addresses Area Load Growth (Long Term, 10 Years)	8	3	5	5
Improves Reliability: SAIDI	8	4	4	3
Net Present Value (2015)	7	4	4	3
Environmental Impact	5	3	3	3
Contingency Solution	5	2	3	3
Power Quality Improvement (SARFI-70)	4	3	3	3
Operating Cost	3	2	3	3
System Loss Savings	3	3	3	3
Total		160	184	169

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Appendix C: Substation One Lines

[redacted]

Appendix D: Property Information

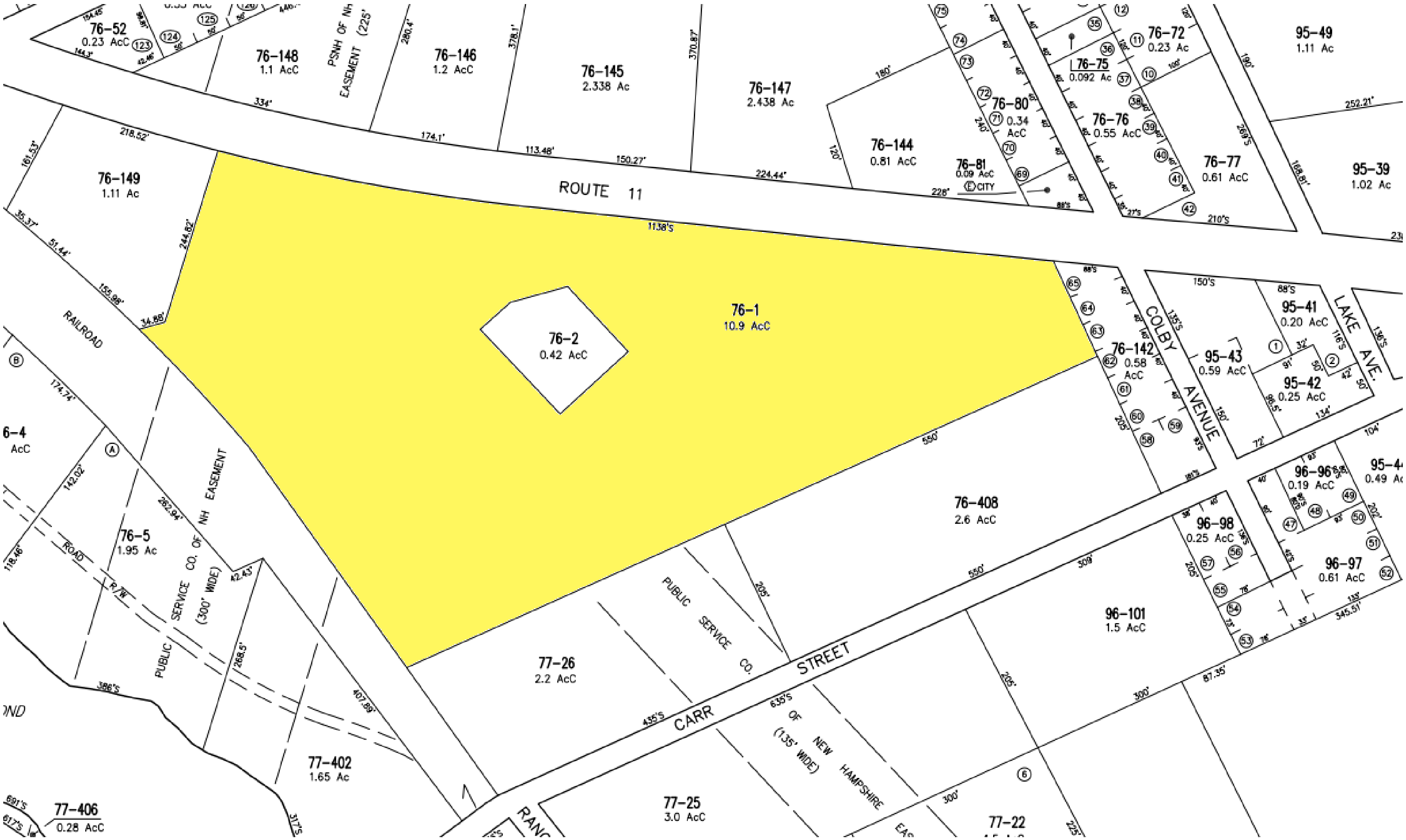

Figure D.1 – 10.9 Acres of land at Webster Substation, not including the NHEC land positioned in the center.

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Appendix E: Webster Area One Line

[redacted]

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Accounting Policy Statement No. 2
Operations Project Authorization

Project Authorization Form

General Information

Date Prepared: 03/29/2016	Project Title: Webster and Daniel Substations
Company: Eversource NH	Project ID Number: A14W02
Organization: NH Operations	Class(es) of Plant: Distribution
Project Initiator: Russel Johnson	Project Category: Reliability
Project Owner/Manager: [redacted]	Project Type: Specific
Project Sponsor: Jim Eilenberger	Project Purpose: Part of regulatory tracked program? No
Estimated in service date: 09/01/2017	Capital Investment Part of Original Operating Plan? Yes
If Transmission Project: Non-PTF	Supplement to Existing Authorization? Yes
	O&M Expenses Part of the Original Operating Plan? N/A

If Chief Executive Officer or subsidiary board approval is required, document the review by Enterprise Risk Management (ERM) and Financial Planning and Analysis (FP&A)

ERM: ____

FP&A: ____

Executive Summary

Webster Substation is a [redacted] serving Eversource and NH Electric Coop (NHEC) [redacted] Load growth in the area will require that additional capacity be installed by 2018 which means that the three small transformers (56 MW installed capacity) will need to be replaced with two larger standard 44.8 MVA units (89.6 MW installed capacity). Other major issues in the substation include an undersized 35 kV strain bus, no bus tie breakers, four old OCB's, old electromechanical relays, no substation capacitors and no position to hook up a mobile substation. In order to properly use the increased capacity this project includes upgrades that solve all the outlined issues. There is sufficient land available to build a new 35 kV bus with appropriate line breakers, capacitors, a bus tie breaker, a mobile hook up location and new numerical relays. This solution will allow the existing equipment to remain in service while the new equipment is installed. This new yard will be separate from the existing yard and will be named Daniel Substation to differentiate between the two stations. The two new transformers will remain in the existing Webster Substation yard eliminating the need to extend a 115 kV feed to Daniel Substation.

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Accounting Policy Statement No. 2
Operations Project Authorization

Project Costs Summary

($000)	Prior Authorized*	Prior Spend*	2016	2017+	Totals	Supplemental Authorization*
Capital Additions - Direct	$472	$345	$3,639	$6,531	$10,515	$10,043
Customer Contribution	$0	$0	$0	$0	$0	$0
Removals net of Salvage	$0	$0	$63	$101	$164	$164
Total - Direct Spending	$472	$345	$3,702	$6,632	$10,679	$10,207
Capital Additions - Indirect	$21	$23	$673	$1,298	$1,994	$1,973
Subtotal Request	$493	$368	$4,375	$7,930	$12,673	$12,180
AFUDC	$0	$2	$18	$93	$113	$113
Total Request	$493	$370	$4,393	$8,023	$12,786	$12,293

Initial authorization was for conceptual design and purchase of two abutting properties that were required to support permitting and construction. Supplemental funding is needed to cover the construction portion of the project.

Summary Project Description

Webster Substation is one of five 115-34.5kV interconnected Eversource substations in the Lakes Region feeding distribution load. The projected load growth of 1.25% in the Lakes Region area in addition to specific load additions, such as the addition of manufacturing facilities by [redacted] (3.5MVA) and the proposed station service for the Northern Pass DC-AC converter station, drive the need for more substation capacity.

The existing Webster Substation is a 115 -34.5 kV three transformer substation. The three 115-34.5 kV transformers are:

Transformer	Rating (MVA)	Impedance (%)	Age (yrs)	TB Bkr Age (yrs)
TB37	20	9.0	64	64
TB96	20	9.1	60	64
TB54	16	8.9	61	40

The existing three transformers normally operate in parallel. Because TB54 has the lowest impedance, it is the limiting factor in peak loading of the substation which reaches 17.1 MVA in 2018. There are also three transformer OCBs, one line OCB and electromechanical relays which have targeted programs for replacement. The four 34.5kV OCB's are ranked number 13, 17, 18, and 115 (3216, TB37, TB96, and TB54 respectively) out of the 127 OCB's remaining on the list to be removed. Additionally, a temporary high speed transformer differential protection system has been installed with the expectation that this project will be constructed and electromechanical relaying will be updated. Additional issues include three troublesome transformer differential relays where one was replaced in a temporary manner and the permanent replacement of all three was postponed to be completed with this project. The existing configuration also presents a contingency which results in the loss of two of the three transformers resulting in the remaining transformer becoming significantly overloaded. System Operations has raised this concern

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multiple times and this project will eliminate these concerns. An automatic load shed scheme has not been implemented due to this planned project resolving this issue.

There is limited space in the existing yard along with an odd configuration of 34.5kV structures. Because of the complexity of replacing and adding equipment while keeping the existing system in service, it was decided that building a new switching substation including breakers, capacitors and a mobile hook up on existing property owned by Eversource outside of Webster Substation was safer, less risky, and technically easier. There is room within the existing Webster S/S to install the two new transformers as the old transformers can be removed in a sequence to accommodate installation of the two new transformers.

The project will consist of the installation of two 44.8MVA 115-34.5kV transformers and associated low side breakers which will feed the new switching yard which will have two busses with a bus tie breaker, associated line breakers, two 5.4 MVAR Capacitor banks and provisions for a Mobile Substation hookup. A new control house with all new protection & control systems will be installed to serve the new switching station. Room will exist on the bus to add an additional breaker position if an additional line is needed in the future. Two of the 34.5kV lines loop with lines fed from Laconia Substation providing for the contingent backup of a transformer failure at Laconia Substation or Webster Substation.

Project Authorization

Approver	Approver Name	Approver Signature	Date
Project Initiator	Russel Johnson		
Project Manager	[redacted]		
Plant Accounting	[redacted]		
Manager- Substation Design	Thelma Brown		
Director- System Engineering	James Eilenberger		
Vice President- Engineering	Peter Clarke		
Executive Vice President	Werner Schweiger		
CFO	Jim Judge		

Overall Justification

- Increase capacity and reliability (including a NH Electric Co-op substation) for the Lakes Region of NH.
- The existing transformers have reached their capacity and are approximately 60 years old.
- The existing 34.5kV bus and associated equipment is undersized and needs to be upgraded.
- The old oil circuit breakers are part of a targeted program for replacement and will be removed. The new breakers will be vacuum breakers.
- The old electro-mechanical relays are a part of a targeted program for replacement and will be upgraded to numerical relays. Temporary repairs to troublesome relay equipment are installed in the aisle of the existing control house. This project will remove these and make permanent replacements.

Project Scope

At Webster Substation:
Remove two (2) 115-34.5kV, 20MVA transformers
Remove one (1) 115-34.5kV, 16MVA transformer
Remove five (5) 34.5kV oil circuit breakers
Remove the 34.5kV strain bus
Remove electro-mechanical relays and asbestos panel-board
Install (2) 115-34.5kV, 44MVA transformers and VCBs
Install numerical relays for two transformers
Install numerical relays for two breakers

At Daniel Substation:
Install two (2) 34.5kV transformer VCB breakers
Install three (3) 34.5kV line VCB breakers
Install two (2) 34.5kV capacitor banks
Install one (1) 34.5kV bus tie breaker
Install two (2) 34.5kV bus sections
Install one (1) control house
Install numerical relays for Daniel S/S equipment and lines

Project Objectives

Increase capacity and reliability for the Lakes Region of NH.

- The existing transformers have reached their top ratings and are approximately 60 years old.
- The 34.5kV bus and associated equipment is undersized and needs to be upgraded.
- The oil circuit breakers are part of a targeted program for replacement and will be removed. The new breakers will be vacuum breakers.
- The electro-mechanical relays are a part of a targeted program for replacement and will be upgraded to numerical relays.

Business Process and / or Technical Improvements:

New Hampshire's System Planning and Strategy studied several alternatives and evaluated them based on feasibility, plausibility, reliability, cost, and system operational flexibility. The construction proposed incorporates design standards and justifications from the Distribution System Engineering Manual, as well as Eversource policy ED-3002. The resulting design will be reliable and allow for future growth.

The following matrix compares the Chosen Alternative to Alternatives 1 and 2 below and indicates that it has the highest rating. Alternative 3, while considered in the Alternatives below is determined to not be feasible for addressing all issues and therefore is not included in the matrix.

		RATING 4-5 Superior, 2-3 = Adequate, 0-1 = Inferior		
Rating Factor	**Weight**	**Chosen Alternative** New Site @ Webster w/ 2 Transformers	**Alternative 1:** Existing Site w/ 2 Transformers	**Alternative 2:** New Site @ Webster w/ 1 Transformer Later
Addresses ED-3002 Design Criteria	8	3	3	3
Addresses Area Load Growth (Long Term, 10 Years)	8	5	3	5
Improves Reliability: SAIDI	8	4	4	3
Net Present Value (2015)	7	4	4	3
Environmental Impact	5	3	3	3
Contingency Solution	5	3	2	3
Power Quality Improvement (SARFI-70)	4	3	3	3
Operating Cost	3	3	2	3
System Loss Savings	3	3	3	3
Final Score		184	160	169

The Final Score is the Sum of the Weight X Rating for all Rating Factors

Alternatives Considered (Details)

Alternative 1: Rebuild the Existing Webster Substation with two 44.8 MVA transformers

Remove the three existing bulk transformers from Webster Substation and replace them with two 115 – 34.5 kV, 44.8 MVA transformers. Upgrade the 34.5 kV bus work in order to facilitate the new transformer installation and change out the OCB's in place. Replace electromechanical relays in existing control house.

Target
- Addresses obsolescence and loading issues at Webster Substation.

Positives
- Built within existing substation footprint.
- Immediately resolves all loading and obsolescence issues at Webster Substation.
- Has the least disturbance for abutters.
- Minimal line work would be required.

Negatives
- Does not allow for the existing equipment to remain in service during construction. A mobile transformer would be necessary to facilitate construction and a complex cutover sequence would be required.
- Does not address the lack of substation capacitors and lack of mobile hook up
- Does not allow any room for future expansion.
- Creates difficulty when trying to add future breaker positions or bus ties.
- Existing control house is crowded and would require complex sequence of removals to accommodate new installations

Conclusion
- This is a feasible option that will solve the obsolescence and loading problems but does not allow for any expansion at the site, does not install substation capacitors or create a mobile hook up.

Alternative 2: Construct a New Substation on the Existing Property with One 44.8 MVA Transformer Now and One 44.8 MVA Transformer Later (Daniel Substation)

A new substation will be constructed on the existing property, adjacent to the current Webster and NHEC Webster Substations. Initially, one 115 – 34.5 kV, 44.8 MVA transformer will be added at the new site and TB54 will be retired. Eventually, the existing Webster Substation will be utilized as a transmission yard when a second 115 – 34.5 kV, 44.8 MVA transformer is added to the new site and TB37 and TB54 are retired.

Target
- Addresses loading issues at Webster Substation.

Positives
- Utilizes existing property.
- Immediately resolves all loading issues but not obsolescence issues at Webster Substation.
- Minimal line work would be required.
- Allows for construction with existing equipment remaining in service.
- Eventually allows for future expansion at the existing Webster Substation and allows for expansion at the new substation.

Negatives
- Does not resolve all obsolescence issues immediately.
- Requires construction around the NHEC Webster Substation.
- Costs significantly more to add a second transformer later and construct 115 kV feeds.

Conclusion
- This is a feasible option but will require significantly more money to construct 115 kV lines and add a second transformer in the future so it was eliminated.

Alternative 3: Methods of Load Curtailment Including Battery Storage, Distributed Generation, or Conservation and Load Management

Utilize conservation and load management, battery storage, and/or distributed generation to reduce the loading on Webster Substation and postpone capital spending.

Target
- Addresses only loading issues at Webster Substation.

Positives
- Helps to postpone a capital investment and reduces the amount of spending needed in the short term.

Negatives
- Conservation and Load Management was evaluated and determined not to be a feasible solution.
- Would not be a long term solution and would only delay spending.
- Does not resolve any obsolescence issues.
- Does not solve the overcrowded substation problem to allow for future construction.

Conclusion
- This is not a feasible option since it only temporarily addresses loading issues. Obsolescence issues are not addressed and loading issues would need to be fixed eventually.

Assumptions

The project estimate is based on the assumption that the construction contractor will only need to mobilize once and continue construction through the winter months to meet the schedule.
No unreasonable opposition to this project is expected from permitting agencies or the general public.

Project Schedule

Milestone/Phase Name	Estimated Completion Date
Permitting	Sept – 16
Engineering	Mar – 17
Construction	Jul – 17
Test & Commissioning	Aug – 17
In-Service	Nov - 17

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Accounting Policy Statement No. 2
Operations Project Authorization

Financial Evaluation

Direct Capital Costs ($000)	Prior Spend	2016	2017	2018+	Total
Straight Time Labor		$32	$85	$0	$117
Overtime Labor		$0	$0	$0	$0
Outside Services		$1,610	$3,865	$0	$5,475
Materials		$2,007	$2,666	$0	$4,673
Other, including contingency amounts (describe)	$346	$53	$16	$0	$434
Total	$346	$3,702	$6,632	$0	$10,680

Indirect Capital Costs		2016	2017	2018+	Total
Indirects/Overheads (including benefits)	$23	$673	$1,298	$0	$1,994
Capitalized interest or AFUDC, if any	$1	$18	$93	$0	$112
Total	$24	$691	$1,391	$0	$2,106

Total Capital Costs	$370	$4,393	$8,023	$0	$12,786

Total O&M Costs	$0	$0	$0	$0	$0

Total Project Costs	**$370**	**$4,393**	**$8,023**	**$0**	**$12,786**

Regulatory Approvals

Permits as required by the City of Franklin and the State of New Hampshire.

- Site Plan Approval
- Dredge and Fill Permit (TBD)
- Alteration of Terrain Permit (TBD)
- EPA NOI

Risks and Risk Mitigation Plans

- The loading during construction may require the use of the mobile substation.
- Internal and external resource availability for engineering.
    - Significant effort is being exerted to balance engineering and review work between internal resources and external resources.

- Lack of sufficient, qualified, local construction labor results in the need to import labor which potentially increases costs or lengthen the schedule which will result in project delays.
    - Develop overall strategy for construction allocation.

- Outage cancelled due to unplanned events on the system resulting in schedule delay and potential labor cost to remobilize.
    - Establish and manage outages using proven coordination teams; 1) Construction Management 2) Coordination Meetings 3) Outage Planning Meeting

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ESTIMATE SUMMARY

Project Title: Daniel Substation - New Substation

Project Mgr/Lead: [redacted]

Project Number: A14W0201

TPS # NA

Estimate By: MPD

Date of Estimate: 1-13-16

ISD: 9/1/17

Estimate # P15-096

ESTIMATE SUMMARY

ESTIMATE TYPE: Order of Magnitude

	TOTAL	Prior	2016	2017	2018	2019	2020 and FUTURE
CONSTRUCTION	$3,855,244	$0	$920,092	$2,935,152	$0	$0	$0
ENGINEERING/DESIGN	$1,226,150	$369,702	$603,836	$252,612	$0	$0	$0
LAND	$0	$0	$0	$0	$0	$0	$0
MATERIAL	$4,680,133	$0	$2,032,368	$2,647,765	$0	$0	$0
PROJECT MGR & SUPPORT	$141,735	$0	$60,637	$81,098	$0	$0	$0
REMOVAL	$156,613	$0	$60,840	$95,773	$0	$0	$0
TEST	$425,843	$0	$27,498	$398,345	$0	$0	$0
CONTINGENCY	$861,692	$0	$0	$0	$861,692	$0	$0
ESCALATION	$194,603	$0	$0	$194,603	$0	$0	$0
INDIRECTS	$1,133,366	$0	$368,810	$764,555	$0	$0	$0
AFUDC	$111,434	$0	$18,354	$93,081	$0	$0	$0
Total Cost	**$12,786,813**	**$369,702**	**$4,092,435**	**$7,462,984**	**$861,692**	**$0**	**$0**

Order of Magnitude	**-50%**	-	**200%**
Range	**$6,393,406**	-	**$38,360,438**

COMMENTS:

Project Scope:

It has been determined that the existing Webster 34.5kV Substation Transformers are undersized and need to be replaced. The Webster substation, originally built in the 1940s, has three 115 to 34.5kV transformers which do not meet the existing and future loads. A study was completed for the area and it was determined that the substation transformer and associated 34.5kV bus needs to be upgraded. The current site has six 115kV transmission lines and two 115kV capacitor banks. The control house has the protection for both the 115kV and 34.5kV systems and is near capacity. The decision has been made to replace the existing TB54 (16MVA), TB96 (20MVA) and TB37(20MVA) with two 44.8 MVA transformers at Webster Substation along with building the Daniel Switching Station on the existing property.

The scope as estimated:
In the Webster Substation:

Two (2) new 40MVA, 115kV to 34.5kV transformers.
Two (2) new 34.5 kv Circuit Breakers
Four (4) new Potential Transformers (PT's)
Twelve (12) new Lightning Arresters (LA's)
Three (2) Station Service Transformers 50 kVA (SSVT)
Two (2) Pull-off 34.5 structures for strain bus to new Daniel SS
Installation includes all associated Foundations, structural steel, conduit, cable and new control and relay cabinets.

Removal at Webster includes the following.
Three (3) Transformers 115kV to 34.5kV.
Twelve (12) PTs
Six (6) 34.5 kV Circuit Breakers
Ten (10) 34.5kV Disconnect Switches.
Twenty three (23) 34.5kV LA's
Two (2) 50kVA 34.5kV SSVT's
Also all associated conduit, cable, structural steel, bus and associated control and relay cabinets.

In the new Daniel Switching Station installation includes the following:
Six (6) 34.5 kV Circuit Breakers.
Ten (10) Gang operated 34.5kV Switches
Six (6) Fused 34.5 kV Switches
Twenty one (21) 34.5 kV PT's.
Fifteen (15) 34.5kV LA's
Two (2) 34.5kV 13 MVAR Capacitor Banks
Two (2) Cap Bank Circuit Switchers
Aluminum Bus Tubing
Two Single Circuit 34.5kV Pull off structures
Two (2) Double Circuit 34.5kV Pull off structures.
New Control house with all associated equipment and apurtances including AC and DC panels, batteries and charger.
Installation includes all associated foundations' fencing, lighting, grounding, site preparation, structural steel, conduit, cable and new control and relay cabinets.
Continued on Cover (2).

Estimating/Eng. Mgr	J. C. Case	Date	**S/S Engr Mgr**	T. J. Brown	Date
P&C Engr Mgr	NA	Date	**Proj Mgr/Lead**	P. D. Pinault	Date

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APS 1 - Project Authorization Policy

Supplement Request Form

Supplement Request Form

Approved at August 16, 2018 EPAC

Link to Meeting Minutes

Date Prepared: August 6, 2018	Project Title: Daniel/Webster Project
Company/Companies: Eversource (NH)	Project ID Number: A14W02
Organization: NH Operations	Plant Class/(F.P.Type): Distribution Substation
Project Initiator: Russel Johnson	Project Type: *Specific*
Project Manager: [redacted]	Capital Investment Part of Original Operating Plan? Y
Project Sponsor: James Eilenberger	O&M Expenses Part of the Original Operating Plan? N/A
Current Authorized Amount: $12,786,813	In service date(s): July 1, 2018
Supplement Request: $6,903,606	Other:
Total Request: $19,690,419	

Supplement Justification

This request is for supplemental funding in the amount of $6,903,606 for the Daniel/Webster Project. This supplemental approval will increase the total authorized funding for the project from $12,786,813 to $19,690,419. The original scope and budget of the project is based on the Daniel/Webster PAF which was approved on 05/13/2016. This project was placed in service in July and punch list items are in the process of being complete.

The budget increase is necessary to support:

1. Escalated indirects/AFUDC
2. Civil and electrical scope changes
3. Distribution line work budget increase
4. P&C scope changes
5. Property purchases
6. Extensive screening as required by the City of Franklin
7. Webster control house asbestos ceiling tile removal

For additional information on these scope increases, please see Justification for Additional Resources section below.

Justification for Additional Resources

- Escalated Indirects/AFUDC – $3,093,199
  The original estimate carried 12% as the aggregate for indirects. Throughout the project, the indirects averaged approximately 42%.

- Civil and electrical scope changes – $1,487,891
  After all contracts were in place and the engineering was in progress, several changes to the scope were implemented which include the following:
    - The addition of two low-side breakers (This was needed to sectionalize faults on the express lines.)
    - Webster S/S fence upgrades (This was needed to bring the fence up to the current standards.)
    - Pull-Off structure and foundation changes (The engineering information on these structures was incorrect on the original scope used for bidding.)
    - Daniel Substation grounding changes (The engineering information on the grounding was incorrect on the original scope used for bidding.)
    - The use of a load bank for testing to reduce customer risk
    - Additional conduits (The drawings used to bid out the EPC work showed conduits in areas where direct buried cable was. It was necessary to install conduits to protect the cabling in this area.)
    - Heating blankets for winter conditions
    - Outage delays due to the March storm
    - The addition of a Human Machine Interface at both substations

- Distribution line work budget increase - $1,114,828
  The line engineering, procurement and construction costs for this project were significantly higher than originally estimated. The engineering for the distribution line work was contracted out to TRC. Eversource was responsible for the procurement of materials. The construction was competitively bid to four line contractors. I.C. Reed was the lowest price bid and was recommended by Eversource Purchasing. The original estimate assumed an open wire design with wood poles. During the engineering review process Eversource Engineering Management decided there was a need for covered wire, caissons and steel poles for this application to avoid outages and maintain system reliability. This work also included the line work and setup associated with the installation of the mobile substation which was not in the original scope.

- P&C scope changes – $604,539

  As part of engineering process, Burns & McDonnell visited the Webster substation to review the site drawings and compare them with the existing conditions in the substation. Based on the comparison, Eversource Engineering determined that the site drawings would need to be as-built prior to commencement of the engineering efforts. Also, as a result of the inaccurate drawings in the field, there were several P&C upgrades needed that were not included in the original scope. These upgrades were needed for compatibility of old and new equipment.

After all contracts were in place and the engineering was in progress, several changes to the scope were implemented which include the following:

- Update inaccurate / obsolete record drawings
- Breaker F139 rewiring
- Upgrade and replace sync switches
- Upgrade and revise 115 and 34.5kV sync switches
- Upgrade and replace all obsolete annunciators
- Addition of a DC panel
- Upgrade breaker failure scheme
- Relocate temperature monitor
- Addition of Eastman Falls transfer trip
- Add transformer paralleling scheme
- Add D20 board
- Add Alber battery monitor

- Property purchases - $318,300

  Originally it was thought that the new substation could be constructed on the existing site, however, Eversource Engineering later determined that it would be in Eversource's best interest to purchase the two abutting properties to allow for optimal layout of the Daniel substation. This was decided after the estimate was completed and full funding was approved.

- Extensive screening as required by the City of Franklin – $208,948

  As a condition of the Planning Board approval, the City required not only screening for the substation but also abutting properties which resulted in much higher cost than anticipated.

- Webster Control House Asbestos Ceiling Tile Removal – $29,081

  As part of the original scope, it was known that the contractor would need access above the ceiling tiles for cable tray mounting and wiring. There were no asbestos labels on these tiles but it was decided, for safety reasons, to test the ceiling tiles for asbestos and the results found them to contain asbestos. The ceiling tile removal was contracted out prior to the construction start.

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APS 1 - Project Authorization Policy

Supplement Request Form

Summary of Direct and Indirect Cost Charges:

Category	Previously Authorized	New Estimate	Delta
Engineering	1,226,150	2,290,573	1,064,423
Project Management	141,735	305,125	163,390
Materials	4,680,133	4,530,013	(150,120)
Land	-	318,300	318,300
Construction	4,011,857	5,629,209	1,617,352
Testing & Commissioning	425,843	2,129,200	1,703,357
Contingency & Escalation	1,056,295	150,000	(906,295)
Total Direct Cost Change	**11,542,013**	**15,352,420**	**3,810,407**
Indirects	1,133,366	4,251,888	3,118,522
AFUDC	111,434	86,111	(25,323)
Total Indirects Cost Change	**1,244,800**	**4,337,999**	**3,093,199**
Total Cost Change	**12,786,813**	**19,690,419**	**+6,903,606**

As part of the project management cost control, the variances were submitted monthly to the Distribution Project Budget committee. Based on this, the 2017/2018 budgets were adjusted to account for these changes.

Lessons Learned

The most notable lessons learned include:

The scope document that was provided with the original estimate was conceptual. Several changes to the scope were made as a result of site visits with Burns & McDonnell when comparing the Webster drawings to the existing conditions.

An internal site visit by Engineering was not conducted prior to creating the scope document. Had this been done, the scope document and cost estimate would have been more comprehensive and complete. It would have also identified the drawings issues prior to the EPC bid being submitted and may have avoided the revised P&C scope. A constructability review and walkdown, which will include as-built drawing review will be done on all future projects prior to seeking full authorization and awarding contracts. Project Managers must use the Substation Constructability Walk Down Checklist on all major projects moving forward.

Following the constructability review and walkdown, the scope document will be reviewed to ensure all necessary items are captured to complete the necessary work for the intended scope.

All major projects that are being run by the Major Projects Group, should have cost sheets that will be discussed in the NH Projects Meetings. This will alert the Eversource Project Manager when a project is in need of a supplemental request before the project has gone over budget.

A lessons learned document is being distributed to the Project Management and Engineering groups which will address controls to be instituted for scope development, estimating, project controls, field conditions and substation engineering oversight & design approvals. A Lessons Learned meeting will follow the completion of the documentation and will require approval from the project team, Project Controls, Engineering and the Estimating groups. This meeting will be held on August 20, 2018 to allow sufficient time for corrective actions and future process improvement development. The approval process will be complete on September 30, 2018.

EVERSOURCE

APS 1 - Project Authorization Policy

Supplement Request Form

Supplement Cost Summary

Note: Dollar values are in thousands:

	Prior Authorized	Supplement Request	Total
Capital Additions - Direct	$ 11,485	$ 3,791	$ 15,275
Less Customer Contribution	$ -	$ -	$ -
Removals net of Salvage .5%	$ 57	$ 19	$ 76
Total Direct Spending	$ 11,542	$ 3,810	$ 15,352
Capital Additions - Indirect	$ 1,133	$ 3,120	$ 4,253
AFUDC	$ 111	$ (25)	$ 86
Total Capital Request	$ 12,787	$ 6,904	$ 19,690
O&M	$ -	$ -	$ -
Total Request	**$ 12,787**	**$ 6,904**	**$ 19,690**

Note: Dollar values are in thousands:

	Prior Years	Year 2018	Year 2019	Total
Capital Additions - Direct	$ -	$ 3,791	$ -	$ 3,791
Less Customer Contribution	$ -	$ -	$ -	$ -
Removals net of Salvage .5%	$ -	$ 19	$ -	$ 19
Total Direct Spending	$ -	$ 3,810	$ -	$ 3,810
Capital Additions - Indirect	$ -	$ 3,120	$ -	$ 3,120
AFUDC	$ -	$ (25)	$ -	$ (25)
Total Capital Request	$ -	$ 6,904	$ -	$ 6,904
O&M	$ -	$ -	$ -	$ -
Total Request	**$ -**	**$ 6,904**	$ -	**$ 6,904**

Public Service of New Hampshire

The Northeast Utilities System

SYSTEM PLANNING & STRATEGY

Keene Area

Distribution System Study

May 2, 2012

Approved: James C. Eilenberger

Table of Contents

Executive Summary

One of the recommendations of the 2011 Ten Year Load Flow Study was to perform a comprehensive study of the Keene area distribution system. This study analyzes the 12.47 kV distribution system in the greater Keene area.

The distribution system in this area is served entirely at 12.47 kV and fed by Keene and Swanzey Substations, serving approximately 20,000 PSNH customers. This area is presently experiencing a 3.1% load growth which is expected to continue for the foreseeable future.

Keene Substation is currently crowded with five 115 kV to 12.47 kV transformers which are heavily loaded and nearing their TFRAT ratings. Of a more urgent nature is the fact that the available fault current at the Keene Substation exceeds the interrupting rating of two of the transformer breakers and much of the switchgear. Moreover, the equipment at Keene Substation is old and obsolete.

It is recommended that two new 115 kV to 12.47 kV substations be built to replace the existing equipment currently concentrated at the Keene Substation on Emerald St: one on Emerald St, adjacent to the existing substation; and one in the North section of Keene. This approach will place the sources closer to the load, reduce fault current, and provide separated electrical sources to the area. As the load continues to increase in this area, an additional transformer will be required at the new Keene Substation.

Respectfully submitted:

Rich Rudolf, Team Lead
Krista Butterfield
Mark Fraser
Steve Hall
Bob Mission
Marc Pilotte
Ingrid Rahaim

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I. Introduction

This study addresses the recommendation that was made in the 2011 Ten Year Load Flow Study to complete a comprehensive study of the Keene Area distribution system. The existing system configuration, equipment limitations, system loading and area load growth rate are used to assess future system requirements. The objective of this study is to develop recommendations that address the long term loading requirements and equipment issues.

Since the electric system feeding the greater Keene area is entirely islanded and separated from PSNH's 34.5kV distribution system, this study focuses on serving this area with a 12.47 kV distribution system.

II. System Background

This report summarizes the work of the Keene Area Planning Study Team as it considered the dynamics of the electrical system serving the greater Keene area. Several alternatives were considered by the group. Ultimately, System Planning & Strategy recommends moving forward with the construction of a new North Keene Substation and the rebuilding of the existing Keene Substation to modern standards. These proposed projects will effectively address existing loading, equipment rating deficiencies, obsolescence, power quality, and reliability issues.

III System Analysis

A. Area Problems & Limitations

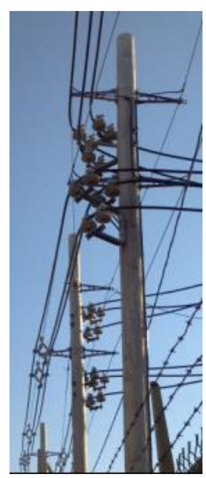
1. **Single Source** – [redacted] This condition could subject multiple circuits to outages from a single event.
2. **Power Quality** – Customers who are sensitive to power quality are affected by disturbances on other Keene Substation circuits due to the interconnected nature of the substation.

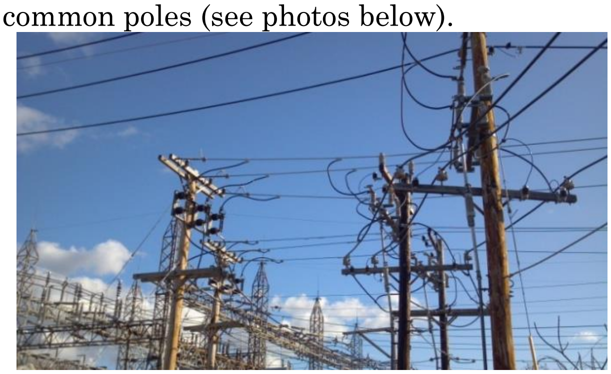
B. Substation Problems & Limitations

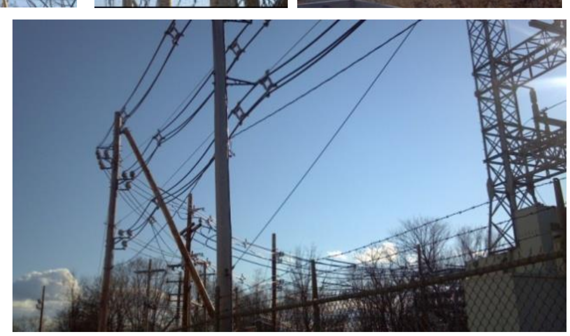
1. **Transformer Breaker Ratings** – Because of the existing transformer impedances and their parallel configuration, the available fault current exceeds the transformer breaker interrupting ratings for TB12 and TB18. (per manufacturer interrupting ratings of 10,000 amps.)
2. **Switchgear Ratings** – System Engineering has identified several breaker ratings which have been exceeded by available fault current. (See Appendix B – PCM report dated 6/24/2009, Vermont 115 kV Southern Loop Expansion – Short Circuit Duty Review)

3. **Obsolescence** – Part of PSNH's strategic plan is to replace obsolete equipment. Four of the five transformers at Keene Substation are between 45 and 60 years old. Based on a useful life expectancy of 55 years for distribution substation equipment, 90% of the distribution equipment at Keene Substation is considered obsolete. Note: Transformer TB3 and its associated equipment, installed in 2000, is excluded from this category.

4. **Limited Capacity** – There is limited line and transformer capacity to serve the area effectively. By 2014, in order to switch out of some contingent transformer outages, up to five load block transfers will need to be made in order to restore all customers. This violates the requirements of Procedure ED-3002.
5. **Congested Physical Site** – The nine (9) 12.47 kV circuits leaving Keene Substation, along with their associated tie switches, encircle the substation, with double- and triple-circuited spacer cable on common poles (see photos below).







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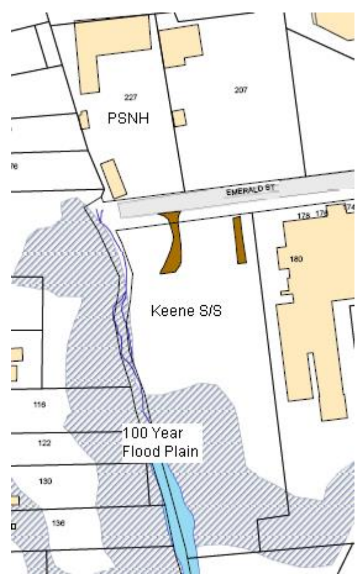
6. **Maintenance Planning** – Maintenance is difficult to schedule on the existing in-service power transformers at Keene Substation, due to loading. Exacerbating the situation is the fact that PSNH does not own a 115 kV to 12.47 kV mobile substation.
7. **Load Growth** – The Loadflow analysis indicates that additional transformation is required prior to the summer of 2014 to resolve all contingent outages without the use of a mobile transformer. With a mobile transformer available, additional transformation is then required prior to the summer of 2020 to address base case overloading conditions.

[redacted]



9. **Proximity to Flood Plain** – Maps furnished by the City of Keene indicate that the southernmost section of Keene Substation falls within the 100-year flood plain (see diagram at right). During the historic flooding event in Keene in the fall of 2005, there was sufficient threat of the substation being submerged that we proposed parking the CL&P 115 - 12 kV mobile substation on Court Street and backfeeding the majority of the city (see LGL document North Keene SS Discussion.doc). During the flooding event in the spring of 2006 – when

the Ashuelot River did overflow its banks – the high water level encroached within three feet of the footings of the fence on the substation's west side. (Sources: Keene DPW; US Army Corps of Engineers)

10. **Environmental Concerns** – Solution options which entail rebuilding the Distribution portion of the station on the 0.97 acre property across the street from the existing station will trigger an environmental evaluation for the use as a substation site. The summary of the Former Keene MGP Final Construction Report (Weston & Sampson Engineers, Inc., September 2005) states: "activity and use restrictions will include direct contact barriers and restrict future excavation and residential use of the site without further risk assessment."

C. **Loadflow Analysis** – A 12.47 kV Loadflow model was developed with all 12.47 kV circuits modeled out to their respective three phase tie points. Circuit and transformer loads were captured for 2011 and escalated out in time at an annual growth rate of 3.1%. Base case loadflows and various contingencies were run. It was determined that additional transformation is required by 2014 to prevent a contingent violation. Specifically, in 2014, it will require five load block transfers for the loss of either TB7 or TB12 at Keene Substation to reduce the loading on its respective parallel-connected transformer to within TFRAT without additional transformation. The first base case violation occurs in 2017 in which the first portion of the W110 circuit, from Keene Substation to the 110DX5 switch, is projected to exceed its 477 ACSR normal conductor rating. (See Appendix D – 12.47 kV Loadflow Synopsis)

IV Solution Options

All of the viable options listed below (Options 2 through 5) involve removal of existing obsolete transformers and switchgear at the Keene Substation, except for TB-3 and its associated circuit reclosers, W2A and W9A, which will stay in service at the South end of the substation yard. In addition, this study assumes that PSNH will complete the procurement of a 115 kV – 12.47 kV mobile substation by 2014, as back-up for a transformer failure. Otherwise, the installation of an additional 30MVA transformer will be required in order to limit the number of load block transfers to three, per ED-3002. This alternative to have a 30 MVA 115 kV to 12.47 kV transformer installed by 2014 is an unrealistic timeframe.

Option 1 – <u>34.5 kV Expansion</u> (Expand at 34.5kV to alleviate substation transformer overloads) –

Approximately 20,000 customers in the greater Keene area are presently served by the existing 115 kV – 12.47 kV distribution system. The closest 115 kV – 34.5 kV sources are Chestnut Hill Substation, Hinsdale (17 miles), Monadnock Substation, Troy (10 miles), and Jackman Substation, Hillsborough (27 miles). The possible circuit ties at the outer extremities of the Keene area are all presently single phase and would therefore not provide suitable ability to offload any significant amount of load. In addition, the deficient substation interrupting ratings issues would still exist at Keene Substation and need to be addressed. Furthermore, for reliability reasons, PSNH has been moving in the direction of expanding its 12.47 kV system where it makes sense rather than serving the area at 34.5 kV, for reliability reasons.

Option 2 – <u>Replacement of Existing Equipment at Keene Substation (Emerald Street) Only</u> –

The Keene (Emerald St.) Substation projects would include:

- Replace TB7, TB12, TB18, and TB23 along with associated switchgear with new equipment at a proposed substation on Emerald St, retaining existing TB3 in service at the original Emerald Street site. This option would be complicated by the requirement to remove existing distribution transformation in order to install the 115kV feed to the new substation lot.
  - **2014 work:**
    - Procure a 115 kV to 12.47 kV mobile substation
  - **2015 work:**
    - Build new 115 kV to 12.47 kV substation with two (2) 30MVA transformers adjacent to the existing Keene Substation.
    - Provide eight (8) breaker positions to feed existing circuitry now fed from the original substation site

Option 3 – <u>Replace Existing Keene Substation and Construct New Distribution Substation (North Keene)</u> –

The Keene (Emerald St.) Substation projects would include:

- Replace TB7, TB12, TB18, and TB23 along with associated switchgear with new equipment at a proposed substation on Emerald St, retaining existing TB3 in service at the original Emerald Street site.
  - **2014 work:**
    - Procure a 115 kV to 12.47 kV mobile substation
  - **2015 work:**
    - Build new 115 kV to 12.47 kV substation with one (1) 30MVA transformer
    - Provide 8 breaker positions to feed existing circuitry now fed from the original substation site

The North Keene Substation projects would include:

- Construct new substation to feed some of the 12.47 kV load from the North end of Keene.
    - **2013 work:**
        - Purchase property to site the new North Keene Substation
    - **2015 work:**
        - Build new 115 kV to 12.47 kV substation with one (1) 30MVA transformer
        - Provide for four feeds to the existing W13, W14, and W1 circuits

Option 4 – Replace Existing Keene Substation and Construct New Distribution Substation (South Keene) –

The Keene (Emerald St.) Substation projects would include:

- Replace TB7, TB12, TB18, and TB23 along with associated switchgear with new equipment at a proposed substation on Emerald St, retaining existing TB3 in service at the original Emerald Street site.
    - **2014 work:**
        - Procure a 115 kV to 12.47 kV mobile substation
    - **2015 work:**
        - Build new 115 kV to 12.47 kV substation with one (1) 30MVA transformer
        - Provide 8 breaker positions to feed existing circuitry now fed from the original substation site

The South Keene Substation projects would include:

- Construct new substation to feed 12.47 kV load from the South end of Keene.
    - **2013 work:**
        - Purchase property to site the new South Keene Substation
    - **2015 work:**
        - Build new 115 kV to 12.47 kV substation with one (1) 30MVA transformer
        - Provide for three feeds to the existing W15, W185 and W2 circuits
        - Provide for one feed to a future W6 circuit

Option 5 – Construct Two New Distribution Substations (South Keene and North Keene) –

The South Keene Substation projects would include:

- Replace TB7, TB12, TB18, and TB23 along with associated switchgear with new equipment at a proposed substation located in the vicinity of the 115 kV crossing of highway Route 101 in Keene, retaining existing TB3 in service at the existing Keene Substation.

- **2013 work:**
  - Purchase property to site the new South Keene Substation
- **2014 work:**
  - Procure a 115 kV to 12.47 kV mobile substation

- **2015 work:**
  - Build new 115 kV to 12.47 kV substation with one (1) 30MVA transformer
  - Provide 8 breaker positions to feed existing circuitry now fed from the original substation site
  - Construct new 12kV line (1800') to connect the new South Keene Substation to the W2 circuit on Winchester St. (Additional line construction will not be needed for the W15 or W185 circuits because both circuits already share the right-of-way crossing with the two 115 kV lines A152 and T198; see picture above.)

The North Keene Substation projects would include:

- Construct new substation to feed 12.47 kV load from the North end of Keene.
  - **2013 work:**
    - Purchase property to site the new North Keene Substation
  - **2015 work:**
    - Build new 115 kV to 12.47 kV substation with one (1) 30MVA transformer
  - **2015 work:**
    - Provide for four feeds to the existing W13, W14, and W1 circuits

Option 6 – <u>Install Distributed Generation</u> –

The installation of distributed generation could defer the base case need for additional transformation in the Keene area; however, it cannot address the equipment obsolescence and inadequate breaker interrupting ratings that presently exist. Significant work would be required at the Keene substation to make this a viable option. This option is not an effective solution.

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V Recommendation

Based on the information contained in this report it is recommended that PSNH:

1. Procure 115 kV to 12.47 kV mobile substation. ISD 2014
2. Construct new North Keene Substation with one 30 MVA transformer and associated switchgear. ISD = 2015
3. Replace existing obsolete equipment at Keene Substation with one 30 MVA transformer and associated switchgear. ISD = 2015 (Note: If environmental issues are uncovered during an environmental risk assessment on the property adjacent to the existing Keene Substation, then a new South Keene substation would be a viable alternative.)

Implementation of the above recommendation will address the following outstanding issues:

- Limited line and transformer capacity to serve the area reliably.
- Maintenance is difficult to schedule on the existing in-service power transformers at Keene Substation, due to loading. Exacerbating the situation is the fact that PSNH does not own a 115 kV to 12.47 kV mobile substation.
- Current [redacted]
- Current one-substation design could potentially cause widespread power quality issues due to localized events.

If the above outstanding issues are not addressed, there is increasing concern that a major outage and continued decline in service quality will result.

PSNH's System Planning and Strategy has studied several options and evaluated them based on reliability, net present value, and system operational flexibility. (See Appendix J – Project Benefit Comparison.) The Keene solution incorporates design standards and justifications from Northeast Utilities Distribution System Engineering Manual, as well as PSNH policy ED-3002. The resulting design will be reliable and allow for future expansion as the economy continues to recover.

Appendix A Substation Transformer Characteristics

Keene Substation

There are five power transformers in service at Keene Substation at the end of Emerald St in Keene. Details of this equipment are listed below.

Transformer TB 18

- Transformer size is 12.5 MVA, voltage class 115 kV to 12.47 kV with Δ / 'Y connected windings.
- Transformer was manufactured in 1953 and installed in 1978.
- Maximum TFRAT rating is 14 MVA.
- Loading on the transformer was 7.69 MVA (July of 2011).
- Three circuits serve a total of 6,368 PSNH customers (shared with TB12).
- The connected secondary switchgear was manufactured in 1949 and installed in 1949.
- The available fault current is at 103% of its interrupting rating of 10,000 amps.

Transformer TB 23

- Transformer size is 12.5 MVA, voltage class 115 kV to 12.47 kV with Δ / 'Y connected windings.
- Transformer was manufactured in 1954 and installed in 1968.
- Maximum TFRAT rating is 13 MVA.
- Loading on the transformer was 7.54 MVA (July of 2011).
- Four circuits serve a total of 7,582 PSNH customers (shared with TB7).
- The connected secondary switchgear was manufactured in 1954 and installed in 1954.
- The available fault current is at 47% of its interrupting rating of 22,000 amps.

Transformer TB 7

- Transformer size is 22.4 MVA, voltage class 115 kV to 12.47 kV with Δ / 'Y connected windings.
- Transformer was manufactured in 1964 and installed in 1969.
- Maximum TFRAT rating is 25 MVA.
- Loading on the transformer was 13.01 MVA (July of 2011).
- Four circuits serve a total of 7,582 PSNH customers (shared with TB23).
- The connected secondary switchgear was manufactured in 1954 and installed in 1954.
- The available fault current is at 47% of its interrupting rating of 22,000 amps.

Transformer TB 12

- Transformer size is 22.4 MVA, voltage class 115 kV to 12.47 kV with Δ / 'Y connected windings.
- Transformer was manufactured in 1969 and installed in 1969.
- Maximum TFRAT rating is 27 MVA.
- Loading on the transformer was 13.33 MVA (July of 2011).
- Three circuits serve a total of 6,368 PSNH customers (shared with TB18).
- The connected secondary switchgear was manufactured in 1949 and installed in 1949.
- The available fault current is at 103% of its interrupting rating of 10,000 amps.

Transformer TB 3

- Transformer size is 22.4 MVA, voltage class 115 kV to 12.47 kV with Δ / 'Y connected windings.
- Transformer was manufactured in 2000 and installed in 2007.
- Maximum TFRAT rating is 26 MVA.
- Loading on the transformer was 18.05 MVA (July of 2011).
- Two circuits serve a total of 2,093 PSNH customers.
- The connected secondary switchgear was manufactured in 2000 and installed in 2000.
- The available fault current is at 56% of its interrupting rating of 12,000 amps.

Swanzey Substation

Transformer TB 2S

- Transformer size is 25 MVA, voltage class 115 kV to 13.09 kV with Δ / 'Y connected windings.
- Transformer was manufactured in 2009 and installed in 2009.
- Maximum TFRAT rating is 30 MVA.
- Loading on the transformer was 8.39 MVA (July of 2011) based on actual thermal ammeter maximum readings.
- Two circuits serve a total of 3,277 PSNH customers.
- The connected secondary switchgear was manufactured in 2009 and installed in 2009.
- The available fault current is at 31% of its interrupting rating of 24,000 amps.

Transformer TB 8S

- Transformer size is 25 MVA, voltage class 115-13.2 kV with Δ / 'Y connected windings.
- Transformer was manufactured in 1991 and installed in 2011 (not in service).
- Maximum TFRAT rating is 30 MVA.
- This transformer would be placed in-service if TB2S failed.

Appendix B Substation Switchgear Characteristics

Vermont 115KV Southern Loop Expansion - Short Circuit Duty Review (DRAFT) 6/24/09 PCM

P&CE (D) has been asked to review the impact on PSNH distribution equipment of proposed changes to the 115 KV in Vermont. The changes in Vermont are specifically defined in "ISO-NE I.3.9 Studies of the Southern Loop".

On May 6, 2008, Vermont Electric Power Company issued a report on the effects caused by the increase in fault currents which will result from the changes in Vermont. The conclusion of that report was that "there are no fault current issues on the 115KV and above voltage system in the area of the project." Potential problems were, however, identified on a 4.16KV bus at Vermont Yankee.

The review of the PSNH distribution equipment in the area of the project was done by using the same short circuit case as that used in the VELCO study and as summarized on May 6, 2008. The case name for ASPEN One-Liner purposes is "2008 NEPOOL Short Circuit Model (Feb) rev 01_ALL NRP-Fitzwilliam_Nominal.OLR on 3/10/08". The only changes made were as follows:

The Swanzey 115KV-12.47KV transformer model was changed to 15MVA per construction currently underway, and the new breaker ratings were applied.

The Jackman GSU was modeled with its estimated new impedance.

The electrical location of the Fitzwilliam 345-115KV tie was corrected per information from [redacted].

Chestnut Hill 34.5 KV, Swanzey (new) 12.47KV, Keene 12.47KV, Monadnock 34.5 KV, and Jackman 34.5 KV were all given a preliminary review of their interrupting ratings. Of those locations, only Keene breakers were within 20% of their nominal ratings, so those breakers were given further analysis.

Keene 12.47KV Breaker Ratings Detailed

Matthew Cosgro contacted GE, who guided him to references which allowed him to detail the capability of the Keene breakers based on their nameplate information, and the application voltage (since the breakers are not nominally rated at 12.47KV). His results are shown on a spreadsheet located at K:\Deptdata\Energy Delivery\Distribution Asset Management\Equipment\Western Central\Keene SS Switchgear Nameplate and Ratings Infomation.xls. This base data was then used to develop interrupting capabilities based on in-service automatic reclose derating using standard P&CE (D) methodology previously developed for 34.5KV oil circuit breakers, and recently confirmed for these air circuit breakers. Specifically, IEEE C37.7-1952 was used for all breakers except for W1, since all but W1 were manufactured in either 1949 or 1954. W1 was manufactured in 1964, in fact has a much higher inherent capability, and was derated for reclosing using C37.010-1999. The results of this derating, along with available fault currents with and without the Vermont expansion, are shown in the spreadsheet on page 3.

By comparing this derated breaker information with today's base case, it was confirmed that the breakers are not currently operating above their theoretical interrupting capability. "Theoretical" is an operative term, however, since some of them are confirmed to be 60 years old as of this year. As shown on the attached spreadsheet, several of the breakers are currently within 5% of their theoretical interrupting ratings, the closest being within 2.56%. This data is shown in the spreadsheet as "3 Phase and L-G Fault Today".

The modestly revised VELCO case (with the changes identified above) was then run using the same fault options as PSNH currently applies to its base case. On the attached spreadsheet this column is identified as " 3 Phase + L-G Fault Future A". This still didn't push any breakers above their capability, and neither did the use of the same case using exactly the same fault options as is used for the New England wide NEPOOL case (see "3 Phase + L-G Fault Future B"), although the closest was within 1.38% of its capability.

It should be noted, however, that these results are for base case conditions, with bus tie breaker 1200 open. There are many alternate feeds to the Keene feeders which could change the results. For example, Keene State College is adding generation to feeder W9A, which poses no interrupting rating issues. For the loss or any outage of TB3, this generation could be tied to Bus #1 through W2A, adding approximately 160A of fault current to the bus total, or enough to put several breakers very close to or slightly over 100% of their capability.

Conclusion

The average increase in fault current on the Keene 12.47KV breakers due to the Vermont system expansion is 1.68%. That said, no breakers on base case are above their calculated interrupting capability today, and none are predicted to be after the Vermont 115KV system enhancements.

Further P&CE (D) Comments on Keene Breaker Ratings

The results of the Keene 12.47 KV breaker review unearthed some facts about Keene which should be documented.

As stated above, there are presently four breakers within 5% of their calculated interrupting capabilities, and a total of 10 within 10%, and there will shortly be a total of eleven breakers within 10% of their capabilities. One breaker is 45 years old, and the rest are between 55 and 60 years old.

The subject of the Keene breaker interrupting capabilities has been raised many times over the last 30 years. There has been, and still is a limit on the use of the bus tie breaker due to the feeder breaker interrupting ratings. Any three transformers in service with the bus tie breaker closed puts the feeder breakers well above their interrupting capability. At one point in the past, GE was approached about “plug and play” breaker modules with higher interrupting capabilities to replace the existing breakers. The subject review raises the question again.

One small step could be taken to increase the margin between the calculated interrupting capability and the available fault current. There are many reclosing combinations in use at Keene today. The IEEE Standard reclose cycle is CO-15 seconds-CO. More than one reclose, and/or any time shorter than 15 seconds reduces the breaker’s interrupting capability. The following reclose combinations shows the impact on the breaker’s nominal interrupting capability. The overall time was assumed to be less than twenty seconds (though preferably 15 seconds) per recent practice.

RECLOSE OPEN TIMES	DERATING FACTOR
1- 5 sec	.9667X
1- 7 sec	.9733X
1-10 sec	.9830X
1-15 sec	1.000X
2 - 5, 5 sec	.9111X
2 - 5, 10 sec	.9265X
2 - 7, 8 sec	.9268X
2 - 7, 13 sec	.9426X
2 - 5, 15 sec	.9425X

This chart shows that more than 5% in breaker interrupting capability can be gained by avoiding multiple short open times. It is suggested that either 1 reclose at 7 - 10 seconds (preferred) or 2 recloses totaling 20 seconds be considered on all Keene feeder breakers until the time when the breakers are changed out.

PCM
6/24/09

KEENE 12.47 KV FAULT DUTY CAPABILITIES WITH VT 115 KV SOUTHERN LOOP EXPANSION 6/24/09

A	B	C	D	E	F	G	H	J	K
YEAR	BREAKER	BRKR RTNG	BRKR RTNG	3 PHASE + L-	PCT	3 PHASE +	PCT	3 PHASE +	PCT
MANUF	(RECLOSE	AT NOM'L V	AT 1.05 PU V	GROUND	COL "E"/	L-GROUND	COL "G"/	L-GROUND	COL "J"/
	OPEN	WITH	WITH	TODAY	COL "D"	FUTURE *A*	COL "D"	FUTURE *B*	COL "D"
	TIMES - SEC)	RECLOSING	RECLOSING			(NOTE 4)		(NOTE 5)	
		AMPS	AMPS	AMPS		AMPS		AMPS	
1949	W15 (5)	11,632	11,078	9,577	86.45%	9,709	87.64%	9,783	88.31%
		11,632	11,078	10,035	90.58%	10,086	91.05%	10,163	91.74%
1949	W110 (5, 10)	11,151	10,620	9,577	90.18%	9,709	91.42%	9,783	92.12%
		11,151	10,620	10,120	95.29%	10,167	95.73%	10,251	96.53%
≤1949	W2 (5, 4)	10,921	10,401	9,577	92.08%	9,709	93.35%	9,783	94.06%
		10,921	10,401	10,120	97.30%	10,167	97.75%	10,251	98.56%
1952	W175 (15)	12,029	11,456	9,577	83.60%	9,709	84.75%	9,783	85.40%
		12,029	11,456	10,120	88.34%	10,167	88.75%	10,251	89.48%
1949	BUS #1 to 1200	12,029	11,456	9,577	83.60%	9,709	84.75%	9,783	85.40%
		12,029	11,456	10,120	88.34%	10,167	88.75%	10,251	89.48%
1954	W185 (10, 10)	11,052	10,525	9,635	91.54%	9,759	92.72%	9,831	93.41%
		11,052	10,525	10,089	95.86%	10,135	96.29%	10,211	97.02%
1954	W14 (6, 16)	11,304	10,766	9,635	89.49%	9,759	90.65%	9,831	91.32%
	(NOTE 7)	11,304	10,766	10,089	93.71%	10,135	94.14%	10,211	94.84%
1954	W13 (5, 10)	10,872	10,354	9,635	93.06%	9,759	94.25%	9,831	94.95%
		10,872	10,354	10,089	97.44%	10135	97.88%	10,211	98.62%
1964	W1 (5, 5)	21,140	20,228	9,398	46.46%	9,523	47.08%	9,596	47.44%
		24,311	23,262	9,839	42.30%	9,886	42.50%	9,962	42.83%
1949	BUS #2 to 1200	12,029	11,456	9,635	84.10%	9,759	85.19%	9,831	85.82%
		12,029	11,456	10,089	88.07%	10,135	88.47%	10,211	89.13%

NOTES:

1) Breaker data and nominal interrupting capabilities supplied by (D) Substation Engineering's Matthew Cosgro.
2) Breaker interrupting ratings "W/RECL'G" (with reclosing) were derated for reclosing based on C37.7-1952, except W1 (C37.010-1999).
3) 3P & L-G faults "TODAY" are based on the PSNH base case Psnh092.
4) 3P & L-G faults "Future A" are from the OneLiner case from VELCO via Jim DiLuca but PSNH Base Case fault options were used. See (6)
5) 3P & L-G faults "Future B" are from the OneLiner case from VELCO via Jim DiLuca; 2008 NEPOOL Case fault options were used. See (6)
6) Non VELCO revisions to the VELCO case: Fitwilliam 115 KV tie corrected, the Swanzey dist xfmr and Jackman Hydro GSU were updated.
7) W14 reclosing with 6, 16 seconds open times assume the existing 0 sec (inst) is removed as planned.

Appendix C Circuit and Substation Loading Characteristics

K:\Deptdata\Energy Delivery\System Plan&Strategy\Comprehensive Studies\Keene Area Study\Report\Study Circuit Loadings.xlsx

K:\Deptdata\Energy Delivery\Distribution Asset Management\System Loading Data\Western Central\Loadings - Keene Monadnock\SS Loading – Keene.xls

Keene S/S Circuit Loadings and Bus Arrangement

Growth Rate: 3.10%

Cust.	Bus 1	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1724	W15	4.6	4.8	4.9	5.1	5.2	5.4	5.6	5.7	5.9	6.1
2468	W110	11.4	11.8	12.2	12.5	12.9	13.3	13.7	14.2	14.6	15.1
	W2	(N.O.)									
1768	W175	8.3	8.6	8.8	9.1	9.4	9.7	10.0	10.3	10.6	11.0
5960		24.4	25.1	25.9	26.7	27.6	28.4	29.3	30.2	31.1	32.1
Cust.	**Bus 2**										
1069	W185	7.48	7.7	8.0	8.2	8.5	8.7	9.0	9.3	9.6	9.8
2315	W13	5.04	5.2	5.4	5.5	5.7	5.9	6.0	6.2	6.4	6.6
1744	W14	4.54	4.7	4.8	5.0	5.1	5.3	5.4	5.6	5.8	6.0
2771	W1	8.23	8.5	8.7	9.0	9.3	9.6	9.9	10.2	10.5	10.8
7899		25.3	26.1	26.9	27.7	28.6	29.5	30.4	31.3	32.3	33.3
Cust.	**Bus 3**										
1145	W9A	9.71	10.0	10.3	10.6	11.0	11.3	11.7	12.0	12.4	12.8
910	W2A	8.93	9.2	9.5	9.8	10.1	10.4	10.7	11.1	11.4	11.8
2055		18.6	19.2	19.8	20.4	21.1	21.7	22.4	23.1	23.8	24.5
15914	**S/S Total**	**68.3**	**70.4**	**72.6**	**74.9**	**77.2**	**79.6**	**82.0**	**84.6**	**87.2**	**89.9**

TFRATs		
bus 1		AFC
TB12	27	10300
TB18	14	
	41	
	95%	39.0
bus 2		AFC
TB23	13	10340
TB7	25	
	38	
	95%	36.1
bus 3		AFC
TB3	26	6720
	95%	24.7

2011 Circuit Loadings		
MVA	MW	MVAR
4.63	4.60	0.50
11.44	11.40	1.00
-		
8.32	8.30	0.60
24.39		
7.48	7.40	1.10
5.04	5.00	0.60
4.54	4.40	1.10
8.23	8.20	0.70
25.28		
9.71	9.50	2.00
8.93	8.90	0.70
18.64		
68.31		

Swanzey S/S Circuit Loadings

Cust.	Swanzey	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1794	4W1	4.46	4.6	4.7	4.9	5.0	5.2	5.4	5.5	5.7	5.9
1992	4W2	4.05	4.2	4.3	4.4	4.6	4.7	4.9	5.0	5.2	5.3
3786	**S/S Total**	**8.5**	**8.8**	**9.0**	**9.3**	**9.6**	**9.9**	**10.2**	**10.5**	**10.9**	**11.2**
19700	**Area Total**	**76.8**	**79.2**	**81.7**	**84.2**	**86.8**	**89.5**	**92.3**	**95.1**	**98.1**	**101.1**

Swanzey		
TB2S	30	
	95%	28.5

2011 Circuit Loadings		
4.46	4.20	1.50
4.05	3.80	1.40
8.51		
76.82		

RER 05/02/2012

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August 23, 2019
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Appendix D 12.47 kV Loadflow Synopsis

Development of PSS/E Model

In order to perform the load flow studies on the Keene 12.47 kV distribution, it was necessary to build the circuit model in PSS/E from scratch as, up until this point in time, the only thing modeled in PSS/E were three bus loads at Keene Substation (representing the total combined load fed from Keene Substation 12.47 kV Buses 1, 2 & 3) and one bus load at Swanzey Substation (representing the entire load fed by Swanzey Substation). It was decided that all mainline sectionalizing devices (those that could be used to transfer load from one circuit to another) would be modeled for each individual 12.47 kV circuit to accommodate the analysis required for contingency operations. The mainline section of a circuit in between sectionalizing devices would be represented as one PSS/E branch, and all collective load in between sectionalizing devices would be assigned to the downstream bus in PSS/E. All radial parts of each 12.47 kV circuit would simply be modeled in PSS/E as one collective bus load, reducing the complexity of the model which is only needed to analyze mainline issues.

All conductor data utilized to calculate branch impedances in PSS/E were gathered from the most recent Keene AWC prints (with input from Field Engineering where discrepancies arose), and all load data utilized for the PSS/E bus loads were taken from the most recent substation load database, provided by Field Engineering, as well as from load data in Field Engineering's Aspen Distriview circuit models (depicting how load is allocated throughout each individual circuit).

It was then decided to employ an annual load growth rate specific to the Keene 12.47 kV distribution in order to reflect a more localized load growth pattern for the load flow analysis. Similar to the summer peak load forecasting performed tor the 12 load flow areas in PSS/E for System Planning & Strategy's Ten-Year Study, the load forecast calculation methodology used in Procedure ED-3029 was utilized to calculate an annual growth rate specific to the Keene 12.47 kV distribution using the total combined annual peak loads of the six 115 kV to 12.47 kV transformers feeding the Keene 12.47 kV distribution. It should be noted, however, that only seven years of historical load data was used in this forecasting calculation, as opposed to ten year's worth of load data as prescribed in ED-3029, as that was all that was available. Nonetheless, upon executing the ED-3029 forecast calculation with the available load data, an annual load growth rate of 3.1% was calculated for the Keene 12.47 kV distribution, which is used to scale all future year loads in the Keene load flow analysis.

Load Flow Analysis

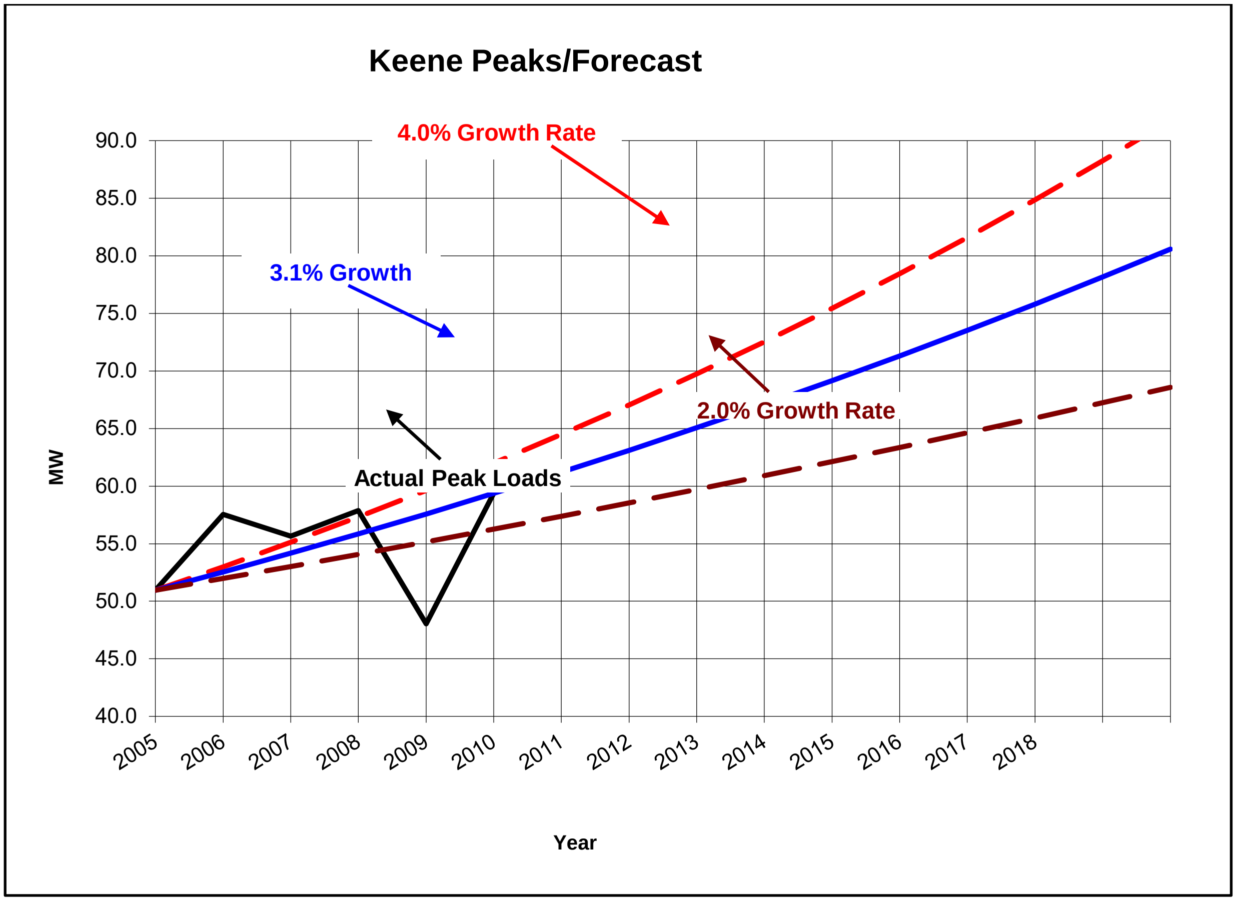
With a proper load flow model developed for the Keene 12.47 kV distribution, the load flow analysis could now be performed, beginning with an initial base case model for 2011. From a purely base case perspective (only looking at base case loading and voltage) and only scaling up the loads from year to year without making any other changes to the model, there are no load flow violations until the year 2017. At this point in time, it is projected that the first 6,300' of the W110 circuit from Keene Substation to the 110DX5 switch (477 ACSR) exceeds its normal rating. Without making any changes to the model and continuing to scale the loads, the next violation occurs in 2020 when TB3 at Keene Substation is projected to exceed 95% of its 26 MVA TFRAT rating. Also, in that same year, it is projected that the first 1,050' of the W2 circuit from Keene Substation (336 ACSR) exceeds its normal rating.

However, when also taking contingency analysis into account, the first load flow violation is actually expected to occur in 2014 upon contingent loss of either TB7 or TB12 at Keene Substation. Both scenarios simulate the loss of a 22.4 MVA transformer (TB7 or TB12) while the smaller 12.5 MVA parallel-connected transformer (TB23 or TB18 respectively) becomes overloaded. Both contingency scenarios also require five load block transfers in order to reduce the loading on TB23 or TB18 to within their respective TFRAT ratings. In order to limit the number of load block transfers to three in either of these contingency scenarios, load would need to be isolated. However, the accepted load isolation criteria utilized for 34.5 kV contingencies, as illustrated in procedure ED-3002, can't be employed for contingencies on the Keene 12.47 kV distribution because PSNH currently doesn't have a dedicated 115 kV to 12.47 kV mobile transformer. Therefore, no load isolation is acceptable for contingencies involving the Keene 12.47 kV distribution, which means 2014 is the first year where an area solution needs to be determined for the existing distribution.

Going one step further as an added measure, it was decided to see if the W6 circuit installation in the 115 kV right-of-way between Keene Substation and Swanzey Substation (currently in the capital budget to be in-service for 2015) would solve the aforementioned contingency violations seen in 2014, assuming the W6 line would be in-service for 2014. With the W6 line added to the PSS/E model, the same contingency analysis was performed. Having the additional W6 line available does enable the number of load block transfers to be reduced from five to three to relieve the overloading of TB23 for loss of TB7, resolving the previous violation. However, for loss of TB12, it still requires five load block transfers to relieve the overloading of TB18. The reason for this is that the W6 line, as proposed, would be normally fed by the parallel-connected TB12 and TB18 transformers and would be utilized to feed the Keene State College load that's currently served by the W9 circuit. This approximate 4 MW load swap to the W6 line would increase the base case loading on the TB12/TB18 transformers. Therefore, for a contingent loss of the larger TB12, this additional W6 load actually contributes to the overloading of TB18, thus increasing the amount of load needing to be transferred to reduce the loading on TB18 to within TFRAT. Subsequently, the number of load block transfers needed to accomplish this in 2014 remains at five.

It has therefore been determined that some type of solution needs to be implemented by 2014 in order to prevent violating any design criteria. Since requiring a solution by 2014 doesn't provide adequate time for a long-term permanent construction solution, and since the violation needing to be resolved is a contingency violation rather than a base case loading violation, it is recommended that PSNH acquires a dedicated 115 kV to 12.47 kV mobile transformer. This will not only restore load for certain Keene 12.47 kV contingencies and buy us time until the first base case loading violation is expected in 2017, but having a 115 kV to 12.47 kV mobile transformer readily available will also benefit the Derry area which also has 115 kV to 12.47 kV transformation.

Keene Area Peak Load Forecast:



Appendix E

Keene Substation One-Line Diagram

[redacted]

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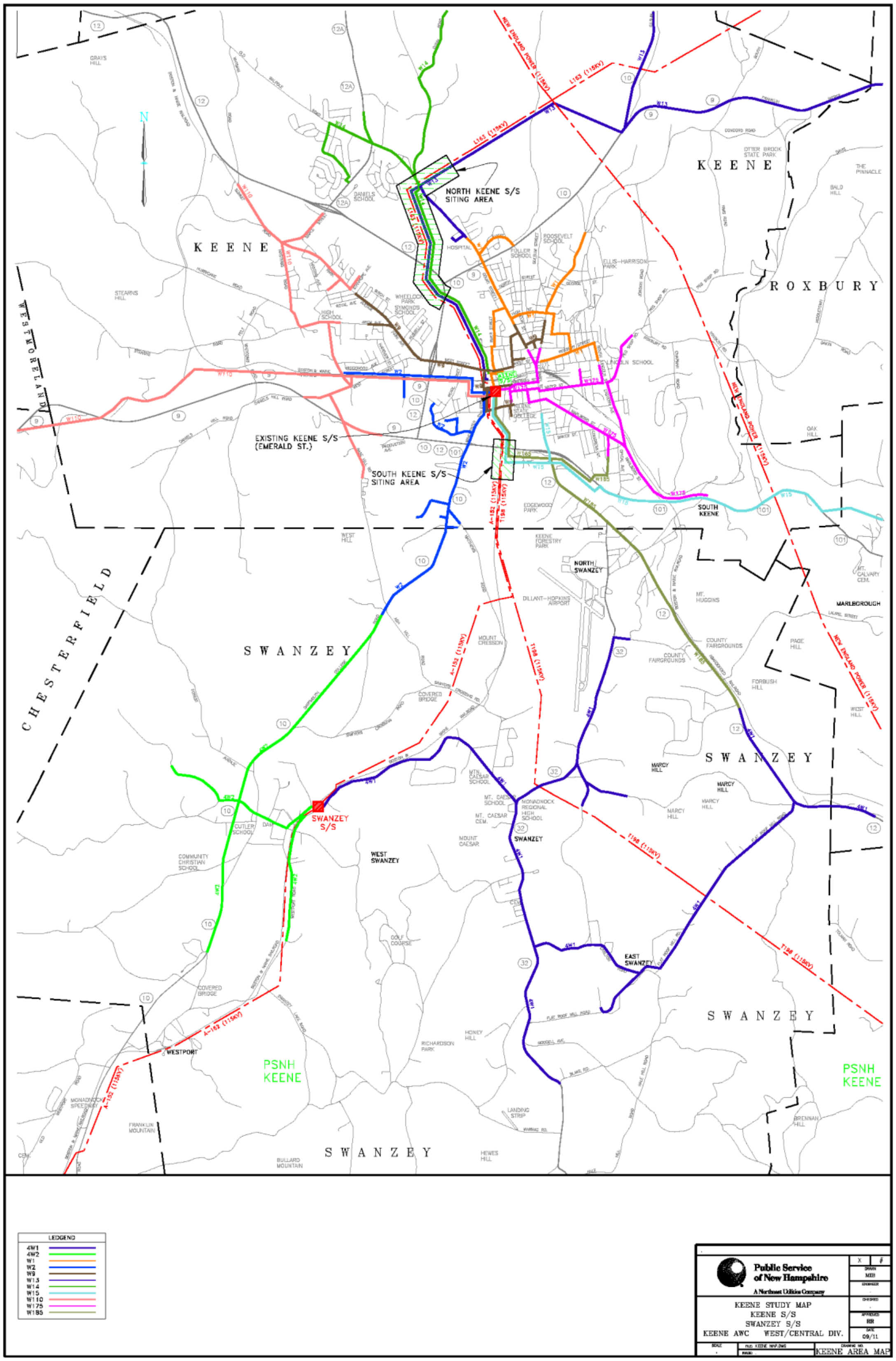
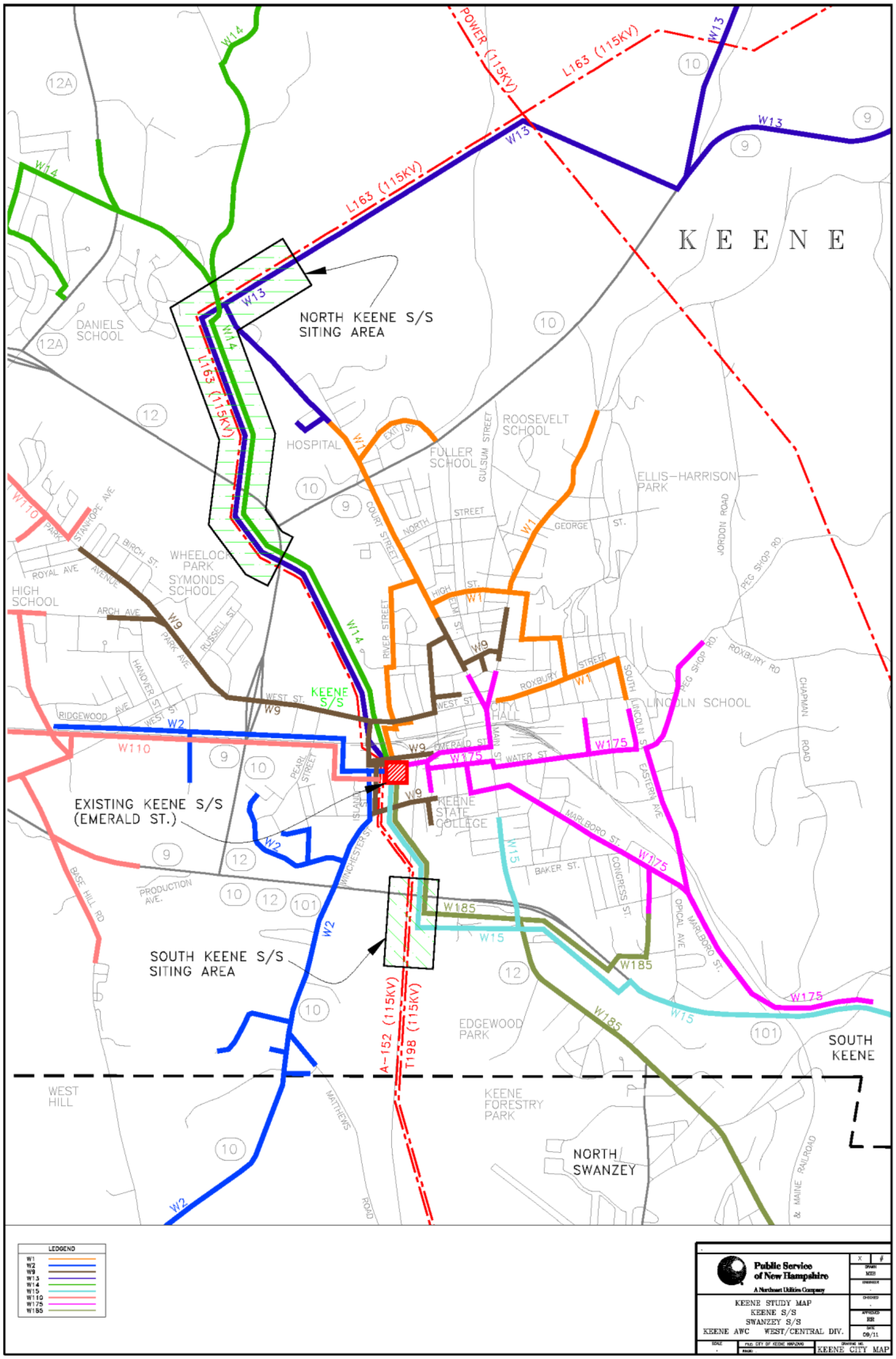
Appendix F Swanzey Substation One-Line Diagram

[redacted]

Appendix G Keene Area 12.47 kV Circuit Diagram



Appendix H City of Keene Circuit Diagram



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Appendix I Cost and Net Present Value Summary

K:\Deptdata\Energy Delivery\System Plan&Strategy\Comprehensive Studies\Keene Area Study\Report\Options Costs T and D.xlsx

Costs are in $Millions

2012 Dollars	New North Keene S/S	Rebuild Emerald St.	Rebuild Emerald St. w/ two units	New South Keene Site
Options				
Distribution S/S	5.94	7.03	7.97	5.94
Distribution Line	1.20	0.50	0.50	0.70
Transmission S/S	12.42	6.00	6.00	12.42
Total	19.56	13.53	14.47	19.06

	Present Value	
Emerald Only	option 2	26.2
No. Keene	option 3	33.7
So. Keene	option 4	33.2
No. & So. Keene	option 5	39.2

The above present values were developed from the information provided below:

Distribution Substation: ([redacted] 2/28/2012)

Please find the high level cost estimates for the Distribution portions of potential Keene area projects. The cost is in 2012 dollars. The estimates are based on ED3064 "Capital Budget Estmating" - DISTRIBUTION SUBSTATION ENGINEERING UNIT COST.

New North Keene S/S: $4.0M - $9.5M
The order of magnitude is conceptual where the scope is similar to a previously completed project and has not been sufficiently defined to make a direct comparison. The expected accuracy ranges from -30% to + 60% and the contingency from 25% to 50% .
Assumptions:
The Distribution cost for one (1) 115 to 12.47 kVtransformer, one capacitor bank and four feeder positions (W1, W13, W14)

Rebuild Emerald Street with two transformers: $6.25M - $12.75M
The order of magnitude is conceptual where the scope is similar to a previously completed project and has not been sufficiently defined to make a direct comparison. The expected accuracy ranges from -30% to + 60% and the contingency from 25% to 50% .
Assumptions:

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The 0.97 A property across the street from existing station is large enough accommodate the 115kV terminals
The 0.97 A property does not require extreme environmental mitigation
Two (2) 115 to 12.47 kV, 30 MVA transformer units
Eight (8) 12.47 kV feeder positions (W15, W110, 75W1&2, W185, W1, W13, W14, spare) , two transformer breaker; provisions for two capacitor banks.
TB3 and bus 3 will remain in the station to feed W9 and W2.
The cost to remove and provide a temporary set-up for TB12 or TB 18 is not included.

Rebuild Emerald Street with one transformer: $5.00M - $11.25M
The order of magnitude is conceptual where the scope is similar to a previously completed project and has not been sufficiently defined to make a direct comparison. The expected accuracy ranges from -30% to + 60% and the contingency from 25% to 50% .
Assumptions:
The 0.97 A property across the street from existing station is large enough accommodate the 115kV terminals
The 0.97 A property does not require extreme environmental mitigation
One (1) 115-12.47kV, 30 MVA transformer units
Eight (8) 12.47 kV feeder positions (includes 2-4 future or spare feeders) , one transformer breaker; provisions for one capacitor bank.
TB3 and bus 3 will remain in the station to feed W9 and W2.
The cost to remove and provide a temporary set-up for TB12 or TB 18 is not included.

New South Keene S/S: $4.0M - $9.5M:
The order of magnitude is conceptual where the scope is similar to a previously completed project and has not been sufficiently defined to make a direct comparison. The expected accuracy ranges from -30% to + 60% and the contingency from 25% to 50% .
Assumptions:
The Distribution cost for one (1) 115 to 12.47 kV transformer, one capacitor bank and four feeder positions (W15, W185, W2)

Transmission Substation: ([redacted]2/27/2012)

The following can be used for budgetary planning. These are high level estimates, once the full scope is defined, new estimates with better detail should be developed.
The costs are in 2015 dollars.

New substation on the north end of Keene
The design would be our standard distribution substation, 2-115 kV breakers with a motor operated switch between the transformers.

The estimate for the transmission only portion of the yard is: **$6.21M - $25.26M**
Order of Magnitude (-50%+200%) estimate:
As the specific location has not been determined, an additional $1.5 mil has been added for land/row costs.

Expansion at Keene
This includes the following assumptions:
Removal of existing 12.47 kV transformers except TB3
Distribution can fit it new facilities on the existing .9 acres currently owned by PSNH
Connections will be underground cable using the former location and facilities of TB 18 and TB12 (approx 500 ft for each transformer)
No 115 kV breakers will be added, assume distribution will be using fully rated circuit switchers at new substation

Underground cables will be included in existing bus protection, distribution will provide sufficient CT's on new transformers for this
Assumes Emerald street can be ended at existing gas facilities and new parcel can be made contiguous with existing land.
Assumes distribution will allow removal of either TB18 or TB12 prior to completion of new substation.

The estimate for the transmission only portion is: **$3M - $12M**

New substation on the south end of Keene:

Same as North Keene estimate:
The estimate for the transmission only portion of the yard is: **$6.21M - $25.26M**
Order of Magnitude (-50%+200%) estimate:
As the specific location has not been determined, an additional $1.5 mil has been added for land/row costs.

Appendix J

Project Benefit Comparison

K:\Deptdata\Energy Delivery\System Plan&Strategy\Comprehensive Studies\Keene Area Study\Report\MATRIX FORM Keene Area Study.xls

Keene Area Study - Matrix for Option Comparison

Project:		Rating 4-5 = Superior, 2 -3 = Adequate, 0-1= Inferior					
Construct New 115-12.47 kV Substations in Keene Area with two 30 MVA transformers in 2015. Remove obsolete equipment in Existing Keene Substation.	Weighting	**Option 1** Expand at 34.5kV to alleviate S/S transformer overloads	**Option 2** Reconstruct 115-12.47 kV Keene S/S with two 30 MVA XFMRs, replacing obsolete equipment at existing Keene S/S.	**Option 3** Construct a 115-12.47 kV North Keene S/S with one 30 MVA XFMR. Replace obsolete equipment at existing Keene S/S with one 30MVA XFMR	**Option 4** Construct a 115-12.47 kV South Keene S/S with one 30 MVA XFMR. Replace obsolete equipment at existing Keene S/S with one 30MVA XFMR	**Option 5** Construct a 115-12.47 kV North Keene S/S with one 30 MVA XFMR. Construct a 115-12.47 kV South Keene S/S with one 30 MVA XFMR. Remove obsolete equipment at existing Keene S/S.	**Option 6** Install Distributed Generation (20MW Combustion Turbine)
Cost			$26.2M	$33.7M	$33.2M	$39.2M	~$45M
Addresses Area Load Growth (Long Term)	8	1	3	5	5	5	1
Improves Reliability: SAIDI	8	1	2	3	3	4	1
Net Present Value (2012) (Appendix A)	7	2	5	4	4	3	2
Feasibility of In-Service Date (ISD)	6	2	2	4	3	3	4
Environmental Impact	5	3	1	2	2	3	1
Contingency Solution	5	1	2	3	3	4	3
Power Quality Improvement (SARFI -70)	4	2	3	3	3	3	2
Operating Cost	3	2	3	3	3	3	2
System Loss Savings (Appendix B)	3	1	1 adds 36.8 kw	4% 3 205.3 kw	2% 2 94.9 kw	6% 4 345.9 kw	4
Total		**79**	**126**	**171**	**162**	**179**	**100**

REDACTED

Technical Authorization Form

TAF # NH-160001-TDS Rev. 0

Date Prepared: November 18, 2016	Project Title: Emerald Street SS Rebuild
Company/ies: Eversource, NH	Project ID Number: A14W01 (D) & T1347A (T)
Organization: NH Operations	Class(es) of Plant: Distribution & Transmission
Project Initiator: [redacted] PE	Project Category: Substation
Project Owner/Manager: Thelma Brown	Project Type: *Specific*
Project Sponsor: James Eilenberger	Project Purpose: part of regulatory tracked program? No
Estimated in service date: December 1, 2018	If Transmission Project: *Non-PTF*
Authorization Type: *Conceptual Engineering*	Authorization Amount: $1,000,000 for Engineering

Project Need Statement *(Description of Issue)*

In 2012 an area study was performed to determine how to best address the area loading and retirement of equipment at the Emerald Street SS. The study recommended two substation projects to replace the existing equipment currently concentrated at the Emerald Street SS in Keene: 1) a new 115-12.47kV substation in the north section of Keene; and 2) a new/rebuilt 115-12.47kV substation on Emerald Street, at the site of the existing substation. This approach places sources closer to the load, addresses aging and overduty equipment, and provides two separate electrical sources to the area.

In November 2016 the North Keene SS was put in-service. This TAF is for the second phase of the 2012 solution, a project which will replace and/or rebuild the existing Emerald Street SS in Keene.

Project Objectives

1. Retire aging infrastructure.

Much of the equipment at Emerald Street substation is more than 50 years old. There are five 115-12.47kV transformers feeding the 15kV switchgear which was installed around 1949.

The testing and maintenance on the transformers has identified that the 47 year old TB-12 is in the worst shape of the transformers with degraded oil and it is recommended that the transformer be reconditioned or replaced. Three of the transformers are more than 50 years old.

Besides the age and condition of the 67 year old switchgear, there is a concern about the fault duty of the equipment. Operating in the normal , the bus 1 and bus 2 switchgear breakers are at 85.40% to 98.62% of their interrupting rating. Because of the fault duty the bus tie breaker must remain open in the switchgear which limits loading on one bus for the failure of a single transformer.

2. Flood Mitigation

The Ashuelot River is near Emerald Street SS and has been identified as a flood threat. When there has been flooding in the Keene area the river level has come up to the south west corner of the substation but not actually flooded the yard. The 500 year flood plain does penetrate the south west corner of the substation. The plan to rebuild the substation will include grading and retaining walls to prevent potential flooding.

3. 115kV Bus Differential Protection

This project will include adding a 2nd 115kV bus differential protection to Emerald Street SS. Emerald Street Substation is classified as a NERC Bulk Electric System (BES) element and is subject to the maintenance and testing requirements outlined in NERC Standard PRC-005-2. This testing includes the trip testing of the 115kV bus differential protection scheme. The existing system lacks redundancy to permit the triup testing without de-energizing the distribution load served by this substation. . The new construction includes adding the equipment and protection to eliminate this exposure to customers. This 2nd 115kV bus differential scheme installation was defined and approved in 2013 in accordance with the

NERC Standard PRC-005-2 relay test requiremens for BES elements. The project was deferred to allow coordination with the proposed transformer changes.

Project Scope

1) Remove four (4) 115-12.47kV transformers (TB3 will remain)
2) Remove existing 15kV switchgear and associated equipment
3) Install two (2) 115-12.47kV 30MVA transformers
4) Install six (6) 115kV CCVTs
5) Install new switchgear with integral control room and associated systems
6) Install underground control cable raceway systems from the existing control house to new switchgear/control house
7) Install new fence and grounding
8) Regrade yard and install a retaining wall to address 500 year flood levels
9) Install yard lighting
10) Install CIP security measures including cameras
11) Protection and control system upgrades including 2nd 115kV bus differential scheme.
12) Install new batteries and monitoring system.

Background / Justification

In 2012 an area study was performed to determine how to best address the loading and retirement of equipment at the Emerald Street SS. The study recommended that two new 115 kV to 12.47 kV substations be built to replace the existing equipment currently concentrated at the Emerald Street SS in Keene: one in the North section of Keene; and one on Emerald Street, adjacent to the existing substation. This approach places sources closer to the load, reduces fault current, and provides two separately located electrical sources to the area.

In November 2016 the North Keene SS was put in-service. This TAF is for the second phase of the study, a project which will replace and/or rebuild the existing Emerald Street SS in Keene. In addition to providing for future peak load in the area, the transformation at Emerald Street SS will be sized to back up North Keene SS which currently has only one transformer but two express lines between the substations.

The switchgear was installed in 1949 and is 67 years old. The transformers were installed at different times and four of the five will be retired by this project:

Transformer	Size(MVA)	Age (yrs)
TB18	12.5	61
TB23	12.5	59
TB7	20	52
TB12	20	47
TB3	20	16 (to remain)

Three of the transformers are over 50 but TB12 condition is of the most concern. The oil fluid quality in the main tank of TB12 is wet, has poor dielectric strength, is dark in color and oxidized, and has low interfacial tension.

Emerald Street (Keene) Substation currently has five 115 kV to 12.47 kV transformers feeding three switchgear busses that cannot be tied together. There are operational issues with the switchgear which limit the flexibility to use bus ties. Closing a bus tie breaker to put three or more transformers on the combined bus puts seven of eight feeder breakers well above their interrupting ability. This is a potential safety risk and limits the loadability and reliability of the substation. Additionally, there are many advantages to upgrading the relay protection as part of the project. In most cases, the existing relaying is as old as the switchgear being replaced, is inflexible as to settings, and gives no remote (or local) access to fault information for event investigation.

This project will include adding a 2nd 115kV bus differential protection to Emerald Street SS. This 2nd 115kV bus differential scheme installation was defined and approved in 2013 in accordance with the NERC Standard PRC-005-2 relay test requiremens for BES elements. The project was deferred to allow coordination with the proposed transformer changes.

Business Process and / or Technical Improvements:

This project addresses aging infrastructure, equipment fault duty, and flood mitigation. It is also a part of the overall area plan and strategy to provide a reliable backup to North Keene SS and provide for future growth.

Cost Estimate and Assumptions

The total price of this project is estimated to cost:

Distribution:	9,500,000
Transmission:	500,000
Total:	$10,000,000

($7,500,000 - $12,500,000) (-25% +25%)

Alternatives Considered with Cost Estimates

Note that this PAF addresses step two in the Alternative recommended in the 2012 Keene Area Study.

Alternative 1: Do nothing.
Emerald Street SS equipment is aging. By doing nothing there is more exposure to customer outages for failure of equipment. The failure of an existing transformer without the proposed 115kV differential system protection results in an outage for all customers fed from Emerald Street SS. Estimated cost for Alternative 1: $0.

Alternative 2: Install a second 115-12.47kV transformer at North Keene SS.
This solution will provide capacity and transformer redundancy at North Keene SS. However, as shown on Attachment A – All circuits were originally fed out of Emerald Street as a hub. North Keene bisects two of the circuits and provides a ROW backup feed to Emerald Street. While this could work load-wise it puts a majority of the circuits on two lines fed from Keene to Emerald Street which is much more exposure to line outages. This may require a switching station at Emerald Street, Keene, potentially switchgear. If this alternative was preferred, additional ROW lines and breakers from North Keene SS are recommended. Estimated cost for Alternative 2: $5,000,000

Alternative 3: Construct a new 115-12.47kV South Keene SS.
North Keene SS was constructed to feed the circuits to the north of Emerald Street SS. A second substation could be constructed south of Keene to address the load. Originally this solution was not preferred partially because of the difficulty of finding a location that is not within the 100 year flood plain. Estimated cost for Alternative 3: $15,000,000

Alternative 4: Construct the Emerald Street SS with one 115-12.47 transformer instead of two.
This alternative will save approximately $1,000,000. It does remove a level of reliability from the solution. This also limits future growth. Between the North Keene SS and Emerald Street SS projects, the effective capacity in the Keene area will be reduced by 5MVA if a second transformer is not installed with this project. Estimated cost for Alternative 4: $9,000,000.

Project Schedule

Milestone/Phase Name	Estimated Completion Date
TAF Approval	12/15/16

Milestone/Phase Name	Estimated Completion Date
Scoping Document Development	12/31/16
Engineering & Design	9/1/17
PAF Approval	9/1/17
Construction	12/1/18
Substation tested, In-Service and Complete	12/1/18

Regulatory Approvals

ISO-NE Level 1 approval for the distribution transformer replacements will be required.

Permitting required by the City of Keene, the State of New Hampshire or US Regulatory Departments

Permitting for excavations on the site of a former MPG site.

Risks and Risk Mitigation Plans

The difficulty of constructing, in effect, around an active station. This will be mitigated by getting a thorough engineering design including identification of phasing for construction and a complete constructability reviews.

Outages cancelled due to unplanned events on the system resulting in schedule delay and potential labor cost to remobilize.

- Mitigation Plan - Establish and manage outages using proven coordination teams; 1) Construction Management 2) Coordination Meetings 3) Outage Planning and Risk Mitigation Meeting 4) Utilization of the circuit ties to North Keene Substation and 5) Deploying a mobile substation (MX66 – CL&P mobile) as required.

Internal and external resource availability for engineering.

- Effort is being exerted to balance engineering and review work between internal resources and external resources.

- Lack of sufficient, qualified, local construction labor results in the need to import labor which potentially increases costs or lengthen the schedule which will result in project delays.
    - Develop overall strategy for construction allocation.

References

Keene Area Study Report

Scope Document

One-Line Diagrams, Attachments, and Images

[redacted]

WESTERN

EVERSOURCE ENERGY
NEW HAMPSHIRE

EMERALD ST. 115/12.47KV
EMERALD STREET, KEENE, NH
357-3545

SKT-EMERALD
12/5/16
LJG

[redacted]

WESTERN

EVERSOURCE ENERGY
NEW HAMPSHIRE

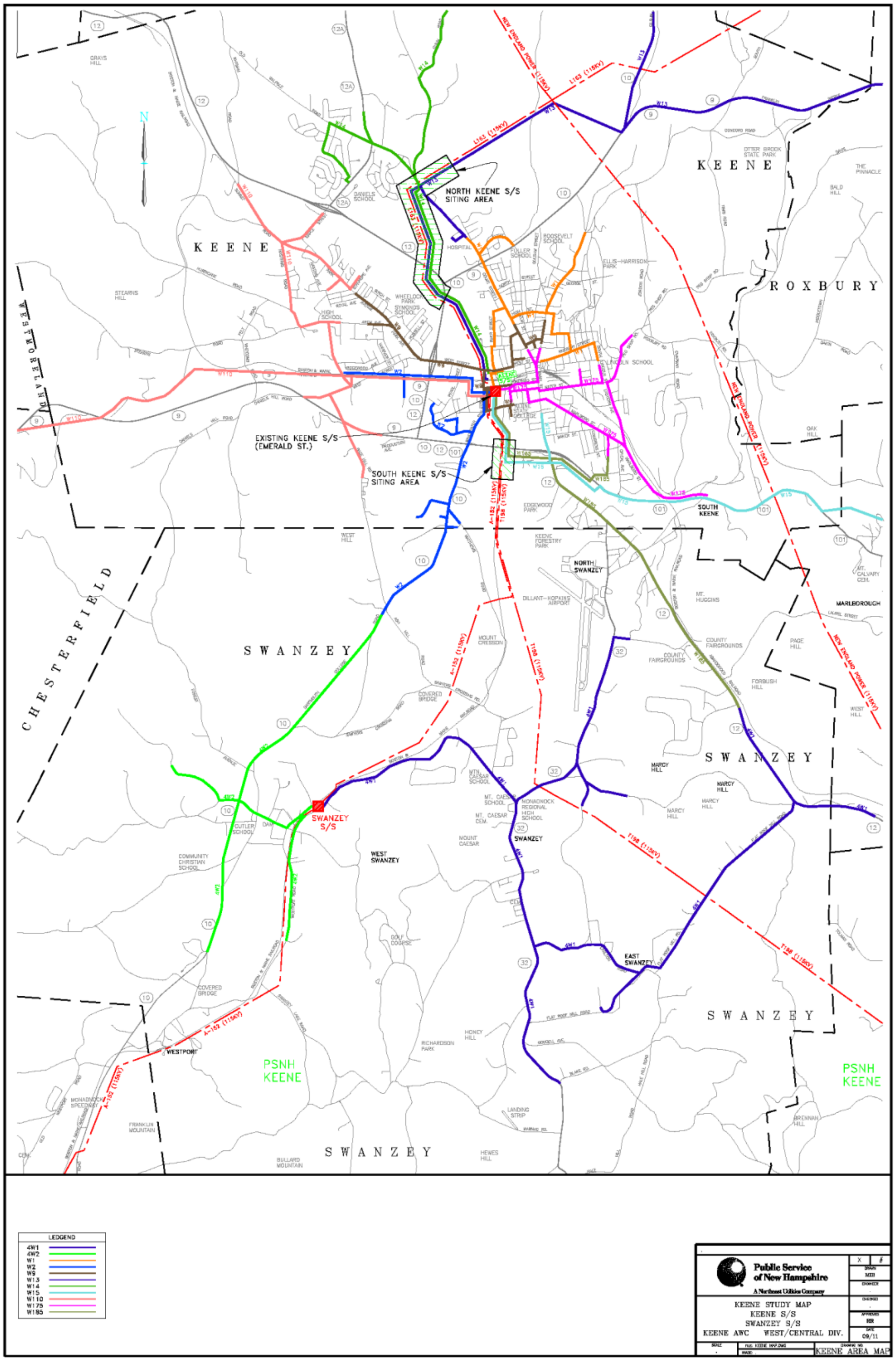
EMERALD ST. 115/12.47KV
EMERALD STREET, KEENE, NH
357-3545

SKT-EMERALD

11/15/16

LJG

ATTACHMENT A - KEENE AREA CIRCUITS



REDACTED

Operations Project Authorization Form

TAF # NH-160001-TDS

Date Prepared: March 10, 2017	Project Title: Emerald Street SS Rebuild
Company/ies: Eversource NH	Project ID Number: A14W01 (D) & T1347A (T)
Organization: NH Operations	Class(es) of Plant: Distribution & Transmission
Project Initiator: [redacted] PE	Project Category: Substation
Project Manager: Thelma Brown	Project Type: *Specific*
Project Sponsor: James Eilenberger	Project Purpose: part of regulatory tracked program? N
Estimated in service date: December 31, 2018	If Transmission Project: Non-PTF
Eng. /Constr. Resources Budgeted? Yes	Capital Investment Part of Original Operating Plan? Yes
	O&M Expenses Part of the Original Operating Plan? NA

Project Authorization

Project authorization must be in accordance with the approval levels included in the Delegation of Authority Policy (DOA).

If Subsidiary Board approval is required, document the review by Enterprise Risk Management (ERM) and Financial Planning and Analysis (FP&A)

ERM: ____

FP&A: ____

Executive Summary

This project is currently approved for $1,000,000 for engineering (see attached TAF). The approval for the transformers and switchgear in addition to the engineering previously approved adds up to the request for a total of $5,300,000 for this project.

This PAF is a request for approval to place long lead-time materials on order for the Emerald Street SS rebuild project. This request includes material funding of $4,300,000 for:

> Two 30MVA 115-12.47kV transformers. Transformers are estimated at $900,000 each for a total of $1,800,000. The lead time for transformers is approximately 52 weeks. The transformer needs to be delivered to the project in Q2 2018.
>
> 12.47kV Metalclad switchgear including fifteen (15) breakers and a control house enclosure. This switchgear is estimated at $2,500,000. The lead time for switchgear is approximately 52 weeks. The switchgear needs to be delivered to the project in Q2 2018.

This project is for the rebuild of the existing substation. Much of the equipment at Emerald Street substation is more than 50 years old. There are five 115-12.47kV transformers feeding the 15kV switchgear which was installed around 1949. There are issues with equipment condition, fault duty, and flooding at the site that will be addressed with this project.

The risk in procuring the transformers if the project does not go forward is limited. This transformer is the standard voltage used in the western part of the Eversource NH system. If this project is not approved the transformers will become system spares and be available for replacement of a failed unit. There are currently 7 of these units in-service including the 5 at Emerald Street SS. In the event it is decided to cancel the order within 20 weeks of placing it, the risk is a partial cost of the transformers. Below is a typical cancellation schedule for a recent transformer purchase.

Cancellation Schedule

The Purchaser may cancel order only upon written notice and upon payment to the Seller of reasonable and proper cancellation charges. These charges will be based on the following schedule unless separate written agreement is made with Seller:

Time frame is from PO date or letter of Intent date.

0	to	10 weeks	20% of the transformer Selling price
>10	to	20 weeks	80% of the transformer Selling price
>20	to	30 weeks	100% of the transformer Selling price

The risk in procuring the switchgear if the project does not go forward is substantial. There may be cancellation policies that can be negotiated but it is recognized that the approval to procure the switchgear should indicate a preference for the project to go forward, although it could be delayed due to funding in 2018 which would push the in-service date out. A $250,000 deposit payment on the switchgear is due in 2017.

Project Costs Summary

Note: Dollar values are in thousands

Distribution Project A14W01

	Prior Authorized	2017	2018	2020+	Totals
Capital Additions - Direct	$ 860	$ 250	$ 4,050	$ -	$ 5,160
Less Customer Contribution	-	-	-	-	-
Removals net of Salvage ____%	-	-	-	-	-
Total - Direct Spending	$ 860	$ 250	$ 4,050	$ -	$ 5,160
Capital Additions - Indirect	130	-	-	-	130
Subtotal Request	$ 990	$ 250	$ 4,050	$ -	$ 5,290
AFUDC	10	-	-	-	10
Total Capital Request	$ 1,000	$ 250	$ 4,050	$ -	$ 5,300
O&M	-	-	-	-	-
Total Request	$ 1,000	$ 250	$ 4,050	$ -	$ 5,300

Transmission Project T1347A

	Prior Authorized	2017	2018	2020+	Totals
Capital Additions - Direct	$ 45	$ -	$ -	$ -	$ 45
Less Customer Contribution	-	-	-	-	-
Removals net of Salvage ____%	-	-	-	-	-
Total - Direct Spending	$ 45	$ -	$ -	$ -	$ 45
Capital Additions - Indirect	5	-	-	-	5
Subtotal Request	$ 50	$ -	$ -	$ -	$ 50
AFUDC	-	-	-	-	-
Total Capital Request	$ 50	$ -	$ -	$ -	$ 50
O&M	-	-	-	-	-
Total Request	$ 50	$ -	$ -	$ -	$ 50

Financial Evaluation

Provide the following financial information (attach additional detail if summarized items are significant or additional information is needed). Note: Dollar values are in thousands
Distribution Project A14W01

Direct Capital Costs	Year 1	Year 2	Year 3+	Total
Straight Time Labor	60			60
Overtime Labor				
Outside Services	800			800
Materials	250	4,050		4,300
Other, including contingency amounts (describe)				
Total	1,110	4,050		5,160

Indirect Capital Costs	Year 1	Year 2	Year 3+	Total
Indirects/Overheads (including benefits)	130			130
Capitalized interest or AFUDC, if any	10			10
Total	140			140

Total Capital Costs	1,250	4,050		5,300
Less Total Customer Contribution				
Total Capital Project Costs	1,250	4,050		5,300
Total O&M Project Costs				

Transmission Project T1347A

Direct Capital Costs	Year 1	Year 2	Year 3+	Total
Straight Time Labor	5			5
Overtime Labor				
Outside Services	40			40
Materials				
Other, including contingency amounts (describe)				
Total	45			45

Indirect Capital Costs	Year 1	Year 2	Year 3+	Total
Indirects/Overheads (including benefits)	4			4
Capitalized interest or AFUDC, if any	1			1
Total	5			5

Total Capital Costs	50			50
Less Total Customer Contribution				
Total Capital Project Costs	50			50
Total O&M Project Costs				

Note: Explain unique payment provisions, if applicable

Future Financial Impacts:

Provide below the estimated future costs that will result from the project:
Note: Dollar values are in thousands:

Future Costs	Year 2017	Year 2018	Year20__	Year 20__+	Total Future Project Costs
Capital	$ 1,000	$ 9,000	$ -	$ -	$ 10,000
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ 1,000**	**$ 9,000**	**$ -**	**$ -**	**$ 10,000**

Total distribution cost of the project is estimated to be $10,000,000. This is proposed for 2018 construction.

What functional area(s) will these future costs be funded in?___NH Operations___
A representative from the respective functional area is required to be included as a project approver.

If this is other than a Reliability Project, please complete the section below;

Provide below the estimated financial benefits that will result from the project:

Note: Dollar values are in thousands:

Future Benefits	**Year 20__**	**Year 20__**	**Year20__**	**Year 20__+**	**Total Future Project Benefits**
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Describe the estimated future Capital, O&M and/or Other benefits noted above:

This project is to replace aging equipment and address operational concerns with the existing substation.

What functional area(s) will these benefits be reflected in?_____NH Operations_____________

A representative from the respective functional area is required to be included as a project approver.

Asset Retirement Obligation (ARO) and/ or Environmental Cleanup Costs (Environmental Liabilities):

An ARO is a current legal obligation to remove or retire property, plant or equipment at some point in the future. Please refer to APS8 or contact Plant Accounting for further detail.

Is there an ARO associated with this project? If yes, please provide details: No

Are there other environmental cleanup costs associated with this project? If yes, please provide details.

This project is located at a former MPG site and handling of the subsurface materials during construction will need to be monitored. Formal cleanup of the site is complete but this needs to be considered for construction.

REDACTED

Technical Authorization Form

TAF # NH-160001-TDS Rev. 0

Date Prepared: November 18, 2016	Project Title: Emerald Street SS Rebuild
Company/ies: Eversource, NH	Project ID Number: A14W01 (D) & T1347A (T)
Organization: NH Operations	Class(es) of Plant: Distribution & Transmission
Project Initiator: [redacted] PE	Project Category: Substation
Project Owner/Manager: Thelma Brown	Project Type: *Specific*
Project Sponsor: James Eilenberger	Project Purpose: part of regulatory tracked program? No
Estimated in service date: December 31, 2018	If Transmission Project: *Non-PTF*
Authorization Type: *Conceptual Engineering*	Authorization Amount: $1,000,000 for Engineering

Project Need Statement *(Description of Issue)*

In 2012 an area study was performed to determine how to best address the area loading and retirement of equipment at the Emerald Street SS. The study recommended two substation projects to replace the existing equipment currently concentrated at the Emerald Street SS in Keene: 1) a new 115-12.47kV substation in the north section of Keene; and 2) a new/rebuilt 115-12.47kV substation on Emerald Street, at the site of the existing substation. This approach places sources closer to the load, addresses aging and overduty equipment, and provides two separate electrical sources to the area.

In November 2016 the North Keene SS was put in-service. This TAF is for the second phase of the 2012 solution, a project which will replace and/or rebuild the existing Emerald Street SS in Keene.

Project Objectives

1. <u>Retire aging infrastructure.</u>

Much of the equipment at Emerald Street substation is more than 50 years old. There are five 115-12.47kV transformers feeding the 15kV switchgear which was installed around 1949.

The testing and maintenance on the transformers has identified that the 47 year old TB-12 is in the worst shape of the transformers with degraded oil and it is recommended that the transformer be reconditioned or replaced. Three of the transformers are more than 50 years old.

Besides the age and condition of the 67 year old switchgear, there is a concern about the fault duty of the equipment. Operating in the normal , the bus 1 and bus 2 switchgear breakers are at 85.40% to 98.62% of their interrupting rating. Because of the fault duty the bus tie breaker must remain open in the switchgear which limits loading on one bus for the failure of a single transformer.

2. <u>Flood Mitigation</u>

The Ashuelot River is near Emerald Street SS and has been identified as a flood threat. When there has been flooding in the Keene area the river level has come up to the south west corner of the substation but not actually flooded the yard. The 500 year flood plain does penetrate the south west corner of the substation. The plan to rebuild the substation will include grading and retaining walls to prevent potential flooding.

3. <u>115kV Bus Differential Protection</u>

This project will include adding a 2^{nd} 115kV bus differential protection to Emerald Street SS. Emerald Street Substation is classified as a NERC Bulk Electric System (BES) element and is subject to the maintenance and testing requirements outlined in NERC Standard PRC-005-2. This testing includes the trip testing of the 115kV bus differential protection scheme. The existing system lacks redundancy to permit the triup testing without de-energizing the distribution load served by this substation. . The new construction includes adding the equipment and protection to eliminate this exposure to customers. This 2nd 115kV bus differential scheme installation was defined and approved in 2013 in accordance with the NERC Standard PRC-005-2 relay test requiremens for BES elements. The project was deferred to allow coordination with the proposed transformer changes.

Project Scope

1) Remove four (4) 115-12.47kV transformers (TB3 will remain)
2) Remove existing 15kV switchgear and associated equipment
3) Install two (2) 115-12.47kV 30MVA transformers
4) Install six (6) 115kV CCVTs
5) Install new switchgear with integral control room and associated systems
6) Install underground control cable raceway systems from the existing control house to new switchgear/control house
7) Install new fence and grounding
8) Regrade yard and install a retaining wall to address 500 year flood levels
9) Install yard lighting
10) Install CIP security measures including cameras
11) Protection and control system upgrades including 2nd 115kV bus differential scheme.
12) Install new batteries and monitoring system.

Background / Justification

In 2012 an area study was performed to determine how to best address the loading and retirement of equipment at the Emerald Street SS. The study recommended that two new 115 kV to 12.47 kV substations be built to replace the existing equipment currently concentrated at the Emerald Street SS in Keene: one in the North section of Keene; and one on Emerald Street, adjacent to the existing substation. This approach places sources closer to the load, reduces fault current, and provides two separately located electrical sources to the area.

In November 2016 the North Keene SS was put in-service. This TAF is for the second phase of the study, a project which will replace and/or rebuild the existing Emerald Street SS in Keene. In addition to providing for future peak load in the area, the transformation at Emerald Street SS will be sized to back up North Keene SS which currently has only one transformer but two express lines between the substations.

The switchgear was installed in 1949 and is 67 years old. The transformers were installed at different times and four of the five will be retired by this project:

Transformer	Size(MVA)	Age (yrs)
TB18	12.5	61
TB23	12.5	59
TB7	20	52
TB12	20	47
TB3	20	16 (to remain)

Three of the transformers are over 50 but TB12 condition is of the most concern. The oil fluid quality in the main tank of TB12 is wet, has poor dielectric strength, is dark in color and oxidized, and has low interfacial tension.

Emerald Street (Keene) Substation currently has five 115 kV to 12.47 kV transformers feeding three switchgear busses that cannot be tied together. There are operational issues with the switchgear which limit the flexibility to use bus ties. Closing a bus tie breaker to put three or more transformers on the combined bus puts seven of eight feeder breakers well above their interrupting ability. This is a potential safety risk and limits the loadability and reliability of the substation. Additionally, there are many advantages to upgrading the relay protection as part of the project. In most cases, the existing relaying is as old as the switchgear being replaced, is inflexible as to settings, and gives no remote (or local) access to fault information for event investigation.

This project will include adding a 2nd 115kV bus differential protection to Emerald Street SS. This 2nd 115kV bus differential scheme installation was defined and approved in 2013 in accordance with the NERC Standard PRC-005-2 relay test requiremens for BES elements. The project was deferred to allow coordination with the proposed transformer changes.

Business Process and / or Technical Improvements:
This project addresses aging infrastructure, equipment fault duty, and flood mitigation. It is also a part of the overall area plan and strategy to provide a reliable backup to North Keene SS and provide for future growth.

Cost Estimate and Assumptions

The total price of this project is estimated to cost:

Distribution:	9,500,000
Transmission:	<u>500,000</u>
Total:	$10,000,000

($7,500,000 - $12,500,000) (-25% +25%)

Alternatives Considered with Cost Estimates
Note that this PAF addresses step two in the Alternative recommended in the 2012 Keene Area Study.

<u>Alternative 1:</u> Do nothing.
Emerald Street SS equipment is aging. By doing nothing there is more exposure to customer outages for failure of equipment. The failure of an existing transformer without the proposed 115kV differential system protection results in an outage for all customers fed from Emerald Street SS. Estimated cost for Alternative 1: $0.

<u>Alternative 2:</u> Install a second 115-12.47kV transformer at North Keene SS.
This solution will provide capacity and transformer redundancy at North Keene SS. However, as shown on Attachment A – All circuits were originally fed out of Emerald Street as a hub. North Keene bisects two of the circuits and provides a ROW backup feed to Emerald Street. While this could work load-wise it puts a majority of the circuits on two lines fed from Keene to Emerald Street which is much more exposure to line outages. This may require a switching station at Emerald Street, Keene, potentially switchgear. If this alternative was preferred, additional ROW lines and breakers from North Keene SS are recommended. Estimated cost for Alternative 2: $5,000,000

<u>Alternative 3:</u> Construct a new 115-12.47kV South Keene SS.
North Keene SS was constructed to feed the circuits to the north of Emerald Street SS. A second substation could be constructed south of Keene to address the load. Originally this solution was not preferred partially because of the difficulty of finding a location that is not within the 100 year flood plain. Estimated cost for Alternative 3: $15,000,000

Alternative 4: Construct the Emerald Street SS with one 115-12.47 transformer instead of two. This alternative will save approximately $1,000,000. It does remove a level of reliability from the solution. This also limits future growth. Between the North Keene SS and Emerald Street SS projects, the effective capacity in the Keene area will be reduced by 5MVA if a second transformer is not installed with this project. Estimated cost for Alternative 4: $9,000,000.

Project Schedule

Milestone/Phase Name	Estimated Completion Date
TAF Approval	12/15/16
Scoping Document Development	12/31/16
Engineering & Design	9/1/17
PAF Approval	9/1/17
Construction	12/1/18
Substation tested, In-Service and Complete	12/1/18

Regulatory Approvals

ISO-NE Level 1 approval for the distribution transformer replacements will be required.

Permitting required by the City of Keene, the State of New Hampshire or US Regulatory Departments

Permitting for excavations on the site of a former MPG site.

Risks and Risk Mitigation Plans

The difficulty of constructing, in effect, around an active station. This will be mitigated by getting a thorough engineering design including identification of phasing for construction and a complete constructability reviews.

Outages cancelled due to unplanned events on the system resulting in schedule delay and potential labor cost to remobilize.

- Mitigation Plan - Establish and manage outages using proven coordination teams; 1) Construction Management 2) Coordination Meetings 3) Outage Planning and Risk Mitigation Meeting 4) Utilization of the circuit ties to North Keene Substation and 5) Deploying a mobile substation (MX66 – CL&P mobile) as required.

Internal and external resource availability for engineering.

- Effort is being exerted to balance engineering and review work between internal resources and external resources.

- Lack of sufficient, qualified, local construction labor results in the need to import labor which potentially increases costs or lengthen the schedule which will result in project delays.
    - Develop overall strategy for construction allocation.

References

REDACTED

Keene Area Study Report

Scope Document

One-Line Diagrams, Attachments, and Images

[redacted]

One-line - Removals

REDACTED

EVERSOURCE

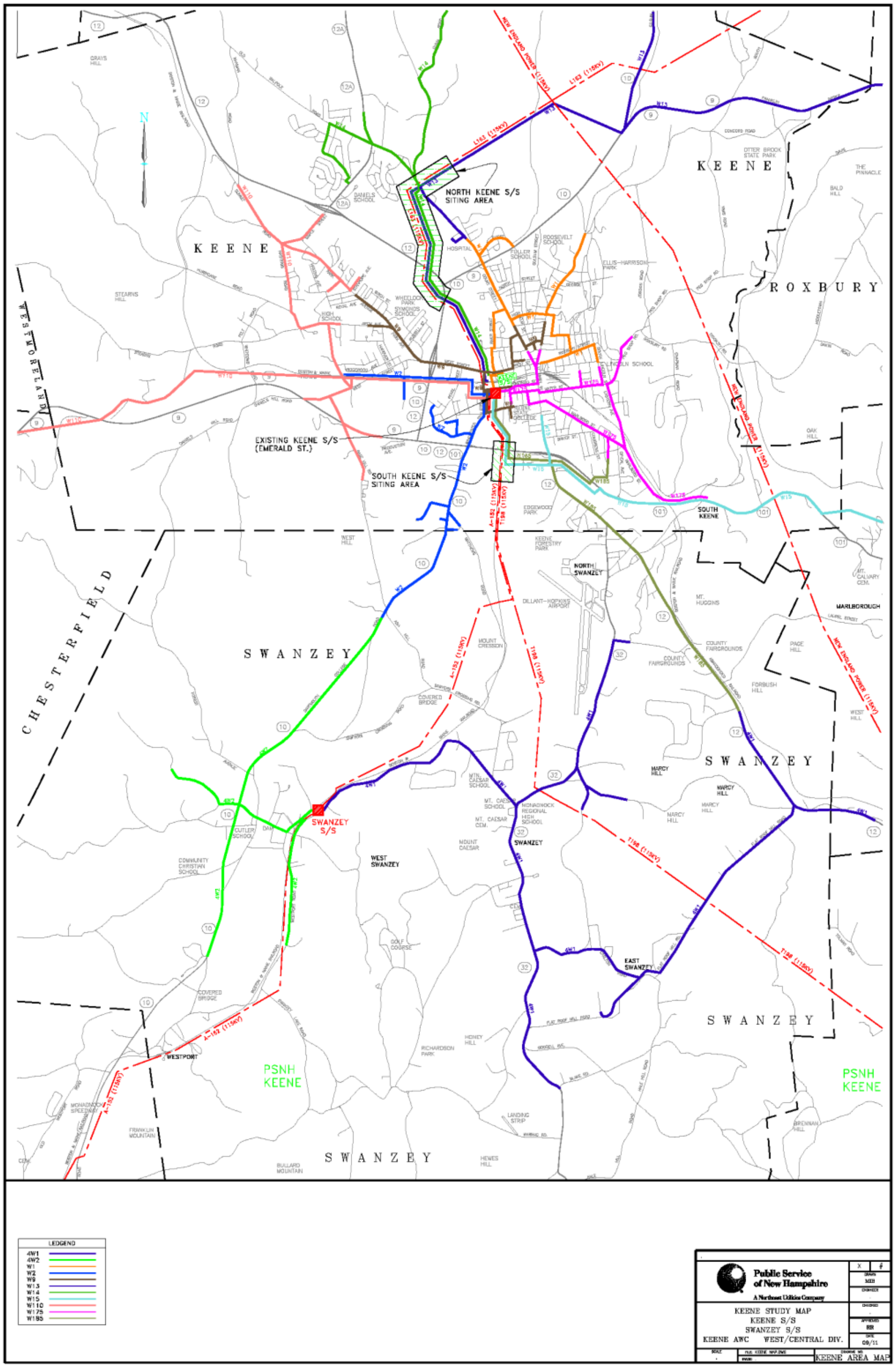
APS 1 - Project Authorization Policy

Appendix 2
Operations Project Authorization Form

[redacted]

One-line - Additions

ATTACHMENT A - KEENE AREA CIRCUITS



Operations Project Authorization Form

Date Prepared: **09/25/17**	Project Title: **Emerald Street**
Company/ies: **Eversource NH**	Project ID Number: **A14W01 (D) & T1347A (T)**
Organization: **NH Operations**	Class(es) of Plant: **Distribution & Transmission**
Project Initiator: [redacted] **PE**	Project Category: **Substation**
Project Manager: [redacted]	Project Type: ***Specific***
Project Sponsor: **James Eilenberger**	Project Purpose: **Replace obsolete equipment**
Estimated in service date: **12/31/18**	If Transmission Project: **Non-PTF**
Eng. /Constr. Resources Budgeted? **Yes**	Capital Investment Part of Original Operating Plan? **Yes**
	O&M Expenses Part of the Original Operating Plan? **No**

Project Authorization

Project authorization must be in accordance with the approval levels included in the Delegation of Authority Policy (DOA).

If Subsidiary Board approval is required, document the review by Enterprise Risk Management (ERM) and Financial Planning and Analysis (FP&A)

ERM: ____

FP&A: ____

Executive Summary

The project scope includes

1) Removing four (4) 115-12.47kV transformers (TB3 will remain)
2) Removing existing 15kV switchgear and associated equipment
3) Install two (2) new 115-12.47kV 30MVA transformers
4) Install nine (9) 115kV CCVTs
5) Install new 15kV switchgear with integral control room and associated systems
6) Adding a second 115kV bus differential protection
7) Replacing obsolete and non-standard 115kV relaying

The joint T&D TAF for this project was approved at the 11/19/16 Technical Review Committee. That approval allowed engineering design to proceed at a cost of $1,000k split $950k (D) and $50k (T).

An initial PAF document was subsequently approved on 03/09/17 for an additional $4,300k to proceed with ordering long lead time materials (transformers and 15kV metal clad switchgear). The Distribution authorized amount was increased from $950k to $5,250k and the Transmission authorized amount remained at $50k.

This PAF now requests full funding of $12,400k (T - $1,400k D - $11,000k) for the project based on known commitments for engineering, Eversource supplied material and firm pricing for the 15kV switchgear. It includes estimates for civil, electrical / P&C construction and Vendor supplied materials. Contingency amounts of $244k and $100k are included in the D & T estimates respectively. The $12,400k estimate is inside the +/-25% of the approved TAF of $10,000k ($7,500 - $12,500).

Since the original TAF, Transmission P&C Engineering has recommended the replacement of several obsolete and non-standard relays at an estimated cost of $750,000. Recommended relay replacements are:

- T1980 breaker failure system: 50/62/BF-T1980: SEL-501 (non-standard breaker failure relay)
- A1520 breaker failure system: 50/BF-A1520: CHC electromechanical BF overcurrent relay; 62/BF-A1520: auxiliary BF timer
- T1980 reclosing system: 79/T1980: ACR electromechanical reclosing relay with 79Y
- A1520 reclosing system: 79/A1520: ACR electromechanical reclosing relay with 79Y
- Currently, all the 115kV breaker failure relays hit a single/shared 86/BF lockout, which is a legacy/non-standard scheme. P&C Engineering recommends replacement with individual lockout coils for each breaker failure relay to match current standards.
- T198 and A152 line relay POTT keying schemes are currently over leased phone lines (via RFL-9745) to Monadnock and Chestnut Hill, respectively. P&C Engineering and Telecommunications Engineering recommend transferring those schemes to the more reliable Eversource fiber.

Based on spend to date, the estimated cost to complete the Distribution portion of the project is $10,820k and $1,354k for Transmission.

Project Costs Summary

See APS3 and APS8 requirements and consult with Plant Accounting for capital/O&M determination. Use published loaders for benefits, materials, and invoices, maintained by the Director, Budget and Internal Reporting.
Note: Dollar values are in thousands

A14W01 *($k)*	Prior Authorized	2017	2018	Totals
Capital Additions - Direct	$12	$819	$7,797	$8,628
Less Customer Contribution	$0	$0	$0	$0
Removals net of Salvage___%	$0	$0	$385	$385
Total – Direct Spending	$12	$819	$8,182	$9,013
Capital Additions – Indirect	$0	$197	$1,627	$1,824
Subtotal Request	$12	$1,016	$9,809	$10,837
AFUDC	$0	$3	$171	$174
Total Capital Request	$12	$1,019	$9,980	$11,011
O&M	$0	$0	$0	$0
Total Request	$12	$1,019	$9,980	$11,011

T1347A *($k)*	Prior Authorized	2017	2018	Totals
Capital Additions - Direct	$0	$86	$1,253	$1,339
Less Customer Contribution	$0	$0	$0	$0
Removals net of Salvage___%	$0	$0	$60	$60
Total – Direct Spending	$0	$86	$1,313	$1,399
Capital Additions – Indirect	$0	$6	$12	$18
Subtotal Request	$0	$92	$1,325	$1,417
AFUDC	$0	$1	$8	$9
Total Capital Request	$0	$93	$1,333	$1,426
O&M	$0	$0	$0	$0
Total Request	$0	$93	$1,333	$1,426

Prior Distribution authorized amount is for $950k approved at TRC on 11/19/16.
An additional $4,300 for transformer and switchgear purchase was approved at CPAC on 03/09/17.

Prior Transmission authorized amount is $50k that was approved at TRC on 11/19/16.

Financial Evaluation

Provide the following financial information (attach additional detail if summarized items are significant or additional information is needed). Note: Dollar values are in thousands

Distribution Project (A14W01)

Direct Capital Costs	**2016**	**2017**	**2018**	**Total**
Straight Time Labor	$1	$56	$81	$138
Overtime Labor	$0	$0	$0	$0
Outside Services	$11	$485	$2,969	$3,465
Materials	$0	$276	$4,553	$4,829
Other, including contingency amounts	$0	$2	$579	$581
Total	$12	$819	$8,182	$9,013

Indirect Capital Costs	**2016**	**2017**	**2018**	**Total**
Indirects/Overheads (including benefits)	$0	$197	$1,627	$1,824
Capitalized interest or AFUDC, if any	$0	$3	$171	$174
Total	$0	$200	$1,798	$1,998

Total Capital Costs	$12	$1,019	$9,980	$11,011
Less Total Customer Contribution	$0	$0	$0	$0
Total Capital Project Costs	**$12**	**$1,019**	**$9,980**	**$11,011**
Total O&M Project Costs	$0	$0	$0	$0

Transmission Project (T1347A)

Direct Capital Costs	2016	2017	2018	Total
Straight Time Labor	$0	$8	$12	$20
Overtime Labor	$0	$0	$0	$0
Outside Services	$0	$77	$1,081	$1,158
Materials	$0	$0	$60	$60
Other, including contingency amounts	$0	$0	$160	$160
Total	$0	$85	$1,313	$1,398

Indirect Capital Costs	2016	2017	2018	Total
Indirects/Overheads (including benefits)	$0	$6	$12	$18
Capitalized interest or AFUDC, if any	$0	$0	$8	$8
Total	$0	$6	$20	$26

Total Capital Costs	$0	$91	$1,333	$1,424
Less Total Customer Contribution	$0	$0	$0	$0
Total Capital Project Costs	**$0**	**$91**	**$1,333**	**$1,424**
Total O&M Project Costs	$0	$0	$0	$0

- Straight time forecast is based on original project estimate.
- Outside services forecast is based on committed contracts (engineering and project management) plus forecast costs for civil, electrical / P&C construction and testing, etc.
- Material costs are based on $1,371k for transformer purchase plus $1,797k for 15kV switchgear. $1,738k for Eversource purchased materials and miscellaneous vendor supplied materials.

This is NOT a new customer project

Future Financial Impacts:

Provide below the estimated future costs that will result from the project:
Note: Dollar values are in thousands:

Future Costs	**Year 20__**	**Year 20__**	**Year20__**	**Year 20__+**	**Total Future Project Costs**
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

<u>If this is other than a Reliability Project, please complete the section below; N/A</u>

Provide below the estimated financial benefits that will result from the project:
Note: Dollar values are in thousands:

Future Benefits	Year 20__	Year 20__	Year20__	Year 20__+	Total Future Project Benefits
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Describe the estimated future Capital, O&M and/or Other benefits noted above:

What functional area(s) will these benefits be reflected in?____________________________________
A representative from the respective functional area is required to be included as a project approver.

Asset Retirement Obligation (ARO) and/ or Environmental Cleanup Costs (Environmental Liabilities):

An ARO is a current legal obligation to remove or retire property, plant or equipment at some point in the future. Please refer to APS8 or contact Plant Accounting for further detail.

Is there an ARO associated with this project? If yes, please provide details: **No**

Are there other environmental cleanup costs associated with this project? If yes, please provide details. **Forecast includes $50k for soil disposal based on an assumption of 1,000 tons at $35/ton haulage and $10/ton disposal costs.**

REDACTED

EVERSOURCE

Solution Selection Form

Date Prepared: January 28, 2019	**Project Title:** Rebuild Emerald Street SS
Company/ies: Eversource NH	**Project ID Number:** A14W01 (D) **&** T1347A (T)
Organization: NH Operations	**Class(es) of Plant:** Distribution & Transmission SS
Project Initiator: Thelma Brown	**Project Category:** Peak Loading/Reliability-Obsolete Eqmt
Project Manager: [redacted]	**Project Type:** Specific
Project Sponsor: [redacted]	**Project Purpose:** Address Keene area load and replace obsolete equipment at Emerald Street SS
Estimated in service date: 12/31/21	**If Transmission Project: PTF?** Yes

The information required (need, objectives, scope of preferred solution, cost estimate(s), and alternatives analysis) can be supplemented with attachments (i.e. MS Word, MS PowerPoint, MS Excel, PDF files). Attachments should be submitted as separate files and not embedded within this form. Previously approved Initial Funding Request forms or other approved authorizations should be included with the submission of this form as a separate attachment.

Project Need Statement

In 2012 an area study was performed to determine how to best address the area loading and retirement of equipment at the Emerald Street SS. The study recommended two substation projects to replace the existing equipment currently concentrated at the Emerald Street SS in Keene: 1) a new 115-12.47kV substation in the north section of Keene; and 2) a new/rebuilt 115-12.47kV substation on Emerald Street, at the site of the existing substation. This approach places sources closer to the load, addresses aging and over-duty equipment, and provides two separate electrical sources to the area.

In November 2016 the North Keene SS was put in-service. The next phase for the Keene area was rebuild of the existing Emerald Street SS. Full funding of Transmission at $1,644k (approved 6/14/18) and Distribution at $11,011k (approved 12/27/17) was approved for these projects.

Since the approval of these projects the Distribution portion of the work has not changed but additional costs require a request for additional funding. Distribution construction is underway and the SDC is not being requested to review this work.

The transmission scope of work has increased as a result of SCLL review by the Electric System Control Center (ESCC). Three new 115kV circuit breakers are requested for the construction phasing of the project. The options being presented to the SDC have to do with alternatives for transmission construction and funding.

Project Objectives

Transmission - To support the Distribution project requirements. The Transmission scope includes updating transmission equipment to limit exposure of outages to the customers, and layout the system to be more easily maintained in the future.

Distribution - To address loading and replacement of obsolete equipment on the Distribution System (see attached original PAF).

Alternatives Considered with Cost Estimates:

- **Alternative 1:**

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This alternative is to continue with the Distribution as planned based on the approved PAF dated 9/25/17 and the approved Transmission scope of work outlined in the PAF dated 4/25/18. Both of these documents are attached. The proposed one-line is attached.

The positive aspects of this alternative are that it addresses the remaining Protection and Control obsolete equipment replacement. This is also the least cost Transmission Alternative.

It does not provide a tie between 115kV lines A152 and D108. Therefore, during Bus 2 outages required for construction, there will be customers at risk for a SCLL. System Planning reviewed this construction scenario:

When System Planning studies scheduled outages in the short-term, cascading load (offloading an affected area to increase local system capacity for restoration efforts) is acceptable as the review is of an N-1-1 scenario. Current system planning criteria for N-1 distribution studies does not allow cascading load transfers and directs system improvements based on system restrictions found. Restoration switching for contingencies during an Emerald Street Substation 115 kV Bus 2 outage was reviewed with and without cascading switching. When a planned outage occurs between Greggs and Emerald Street, the ESCC (Electric System Control Center) usually institutes some pre-contingent switching to reduce customer exposure. This review looks at the system as-is without any pre-contingent switching.

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EVERSOURCE

Estimated cost of Alternative 1:
Distribution = $15,800k
Transmission = $1,673k

- **Alternative 2**
  This alternative is to continue with the Distribution as planned based on the approved PAF dated 9/25/17. The transmission work will be expanded to include a 115kV circuit breaker tie between the A152 and D108 lines. This circuit breaker will be used during construction. After construction it will be operated normally open and used only for future breaker maintenance. The proposed one-line is attached.

  The positive aspect of this alternative is that it addresses the SCLL issues identified in Alternative 1 to limit customer exposure during Bus 2 construction outages. It also allows for using the breaker during future breaker maintenance, removing the customer exposure to SCLL conditions.

  The challenge to this alternative is that it increases the transmission investment and exposes customers to SCLL conditions during the construction and commissioning of the new 115kV breaker. Alternative 2 costs more than Alternative 1 and will be a local transmission cost.

  Estimated cost of Alternative 2:
  Distribution = $15,800k
  Transmission = $3,246k

- **Alternative 3**
  This alternative is to continue with the Distribution as planned based on the approved PAF dated 9/25/17. The 115kV circuit breaker tie between the A152 and D108 lines from Alternative 2 is included. Two additional circuit breakers are added in the 115kV bus to replace existing switches. The proposed one-line is attached.

  The addition of 115kV bus tie breakers at the Keene substation improves customer reliability and ease of maintenance. For any single bus contingency, all customers can be restored via SCADA switching within 5 minutes. Without bus tie breakers, the single bus SCLL strands approximately 2500 customers due to distribution limitations. Ease of maintenance is increased when a bus section is required OOS. Without bus tie breakers, removing a section of bus from service requires offloading multiple transformers.

  The challenge to this alternative is that it increases the transmission investment and exposes customers to SCLL conditions during the construction and commissioning of the new 115kV breakers. Alternative 2 costs more than Alternative 1 and will be a local transmission cost. There is some concern by P&C regarding the use of the breakers and impact on bus differential scheme relays.

  Estimated cost of Alternative 3:
  Distribution = $15,800k
  Transmission = $4M+ ($3,246k cost from Alt. 2 plus two additional 115-kV breakers)

- **Alternative 4**
  This alternative is to continue with the Distribution as planned based on the approved PAF dated 9/25/17. The three new 115kV circuit breakers in Alternative 3 are included. Instead of being controlled only by SCADA they will be used with three bus differential schemes allowing for a limited exposure to customers for a bus fault.

  The additional benefit of Alternative 4 over Alternative 3 is that the customer reliability is improved by converting a single SCLL of 8560 customers to three separate SCLLs of 1215, 2125, and 5219 customers.

  The challenge to this Alternative is that it has an adverse impact on the system.

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Estimated cost of Alternative 4:
Distribution = Not applicable
Transmission = Not applicable

Because Alternative 4 creates an adverse system impact this alternative was discounted and a conceptual cost estimate was not created.

- **Alternative 5**
  This alternative is to continue with the Distribution as planned based on the approved PAF dated 9/25/17. The transmission will be rebuilt to a 115kV breaker and a half configuration.

  This transmission configuration has many advantages over the existing 115kV straight bus configuration.

  The challenge to this Alternative is that there is no land to expand the substation in this location. In order to complete the distribution project the 115kV straight bus design will need to remain.

  Estimated cost of Alternative 5:
  Transmission and Distribution = $29,380k (2012 dollars)
  Alternative 5 was estimated in TPS# 14-165-NH

  No non-wires alternatives were analyzed for this project. The project's primary objective is to replace obsolete systems. At the transmission level this alternative is a one-for-one replacement and includes a new secondary bus differential scheme.

Project Scope (Preferred Solution)

Alternative 3 is the preferred solution. Attached is the scope document.

This alternative is chosen because it provides the most flexibility and is preferred by Station Operations and ESCC.

Cost Estimate Backup Details

Provide backup details of conceptual grade cost estimates (-25%/+50%) for all appropriate alternatives (at least the preferred solution and leading alternative).

Attachments (maps, images, one-line diagrams, MS PowerPoint presentations, MS Excel cost estimate files, etc.)

Supplement Request Form

Approved at May 03, 2019 EPAC
Link to Meeting Minutes

Date Prepared: April 17, 2019	**Project Title: Emerald Street Substation Rebuild**
Company/Companies: Eversource NH	**Project ID Number: A14W01**
Organization: NH Operations	**Plant Class / (F.P. Type): Distribution Substation**
Project Initiator: Thelma Brown	**Project Type: Specific**
Project Manager: [redacted]	**Capital Investment Part of Original Operating Plan? Y**
Project Sponsor: [redacted]	**O&M Expenses Part of the Original Operating Plan? N/A**
Current Authorized Amount: $11,011K	**Estimated in service date(s): December 31, 2020**
Supplement Request: $5,824K	**PAC: Not Required**
Total Request: $16,835K	**TCA: Not Required**

Supplemental Justification

Distribution Project

In September 2014, TPS-14-165-NH was approved for the construction of a new North Keene substation and the rebuild of Emerald Street substation in Keene, NH. North Keene substation was placed in service in October 2016. TAF # NH-160001-TDS Rev. 0 requested $1,000K for preliminary engineering to rebuild the Emerald Street substation and was approved in PowerPlan on December 19, 2016. A PAF for equipment purchase and additional approved engineering was approved $5.3M in PowerPlan on June 5, 2017. A PAF for full funding for the Distribution portion of the Emerald Street rebuild project was approved in PowerPlan on December 12, 2017 for the current authorized amount of $11,011K.

The original Distribution scope of work, which has not significantly changed, includes the removal of (4) four (of five) transformers, the installation of (2) two new 115/12.47kV transformers, the removal of the existing 12.47kV switchgear, and the installation of new metalclad switchgear along with new protection and control equipment.

Transmission Project

Approval to proceed with the Transmission portion of the rebuild of Emerald Street was provided in October 2017. $50K was approved for preliminary engineering for the Transmission portion of the project to rebuild the Emerald Street substation on February 14, 2017. On April 25, 2018, the PAF for full funding for the Emerald Street rebuild project was approved at EPAC. The project was approved in PowerPlan on June 14, 2018 for the current authorized amount of $1,664K.

The original Transmission scope of work included the installation of three (3) 115kV CCVTs, the replacement of the existing primary bus differential relay, and the addition of a secondary bus differential relay.

In October 2018, it was proposed to expand the scope of the project to include the replacement of several obsolete relays and to add a single 115kV line tie circuit breaker. The relays were added to the scope because the Emerald Street 115kV protection scheme includes several electromechanical relays identified as obsolete by the Eversource Asset Strategy Program for protective relays (RF-AS-9017, Rev. 3). Additionally, the 115kV bus protection and breaker failure schemes are a legacy design that do not meet the current standard.

The addition of a single 115kV line tie was proposed because during the development of the construction outage sequence, the Electric System Control Center (ESCC) highlighted the risk of unacceptable loss of customer load for an N-1-1 contingency. To mitigate this risk, a sub-set of the project team from System Planning, Substation Engineering, Operations, and Project Management proposed a 115kV line tie between the A152 and D108 lines to address these SCLL issues. The permanent line tie circuit breaker replaces a temporary line tie circuit switch which was installed but subsequently removed.

When System Planning studies scheduled outages in the short-term, cascading load (offloading an affected area to increase local system capacity for restoration efforts) is acceptable as the review is of an N-1-1 scenario. Current system planning criteria for N-1 distribution studies does not allow cascading load transfers and directs system improvements based on system restrictions found. Restoration switching for contingencies during an Emerald Street Substation 115 kV Bus 2 outage was reviewed with and without cascading switching. When a planned outage occurs between Greggs and Emerald Street, the ESCC (Electric System Control Center) usually institutes some pre-contingent switching to reduce customer exposure. The following review looked at the system as-is without any pre-contingent switching.

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To address the above findings, it is proposed to continue with the Distribution project as planned based on the approved PAF dated 9/25/17. The scope of the Transmission project would be expanded to add a 115kV circuit breaker tie between the A152 and D108 lines plus two additional circuit breakers added in the 115kV bus to replace existing switches. These two bus tie breakers will be operated via SCADA for switching operations only and will not be tied into the existing bus protection systems. The addition of 115kV bus tie breakers at the Keene substation improves customer reliability and ease of maintenance. For any single bus contingency, all customers can be restored via SCADA switching within 5 minutes. Without bus tie breakers, the single bus SCLL strands approximately 2500 customers due to distribution limitations. Ease of maintenance is increased when a bus section is required OOS. Without bus tie breakers, removing a section of bus from service requires offloading multiple transformers. The revised scope was approved by the chair of the Solution Design Committee on March 26, 2019.

While the addition of the proposed 115kV line tie will only be used during construction and for maintenance, ISO-NE will require a new I.3.9 submission. This has been discussed with ISO-NE and no issues are anticipated. The additional bus tie breakers will not be provided with protective relaying and therefore create no new contingencies. As such an I.3.9 submission is not required for the bus tie addition. All work at Emerald Street is classed as Local and no TCA is required.

A supplemental request for an additional $3,930K for a total request of $5,594K for the Transmission portion of the Emerald Street project accompanies this document. The scope of work for the Transmission project now includes the installation of three (3) 115kV CCVTs and a second 115kV bus differential relay, the replacement of the existing 115kV bus differential relay, the replacement of various obsolete relays and the installation of three (3) 115kV circuit breakers, associated disconnects and protection and control equipment.

The operational requirement for the line and bus tie breakers increased the cost of the Transmission project. It also impacted the cost of the Distribution project because it requires the creation of multiple engineering drawing packages and extends the duration of the project.

Project Status

As of the end of March 2019, the project has invested $6,082K with additional commitments of $2,500K for work done but not yet invoiced. Commitments include $1,061K for remaining switchgear payments due in April 2019. Total spend to-date plus commitments is approximately $8,582K out of $11,011K authorized.

Civil and electrical IFC drawings have been issued to the Contractor and construction started on January 7, 2019. The new switchgear arrived on site on April 10, 2019 and the two (2) replacement transformers have been delivered to the site.

This supplement requests approval of $5,824K for a total request of $16,835K, an increase of 46% over the current authorized amount. The primary driver for the additional cost is due to unforeseen construction costs, the need to split the P&C drawings into several phases due to an extended outage schedule and associated additional labor costs due to a longer construction schedule. The details for the increase are explained below.

Cumulative effect of Changes since September 2017

Justification for Additional Resources

The reasons for the project authorization supplement of $5,824K are summarized below:

1) **Company Labor ($202K):** The original construction schedule was based on an in-service date of December 2018. With the requirement to construct a new 115kV line tie for the transmission portion of the project, the project duration has increased and the final in-service date for the Distribution portion of the project is now December 2020. The longer construction schedule increases the amount of time needed for Construction supervision and safety coverage. It also increases the amount of Engineering time needed to review and comment on multiple drawing packages.

2) **Project Management ($62K):** The estimate for Project Management services in September 2017 was based on the hours needed to complete the project in December 2018. Because the Transmission portion of the project scope has expanded, the construction sequence for the Distribution portion of the project was extended until December 2018**.** The forecasted PM costs have increased from $125K to $187K.

3) **Engineering ($299K)**: The estimate for Engineering design has increased from $460K to $759K due to the need to generate multiple IFC drawing packages associated with the phased approach needed to incorporate the 115kV line tie into the overall project scope. Initially a single construction sequence was envisaged which only required one-set of P&C drawings. Because it was not operationally acceptable to take 115kV Bus 1 and Bus 2 outages, an additional 115kV line tie breaker is needed. This work will create a significant break in the schedule and requires multiple sets of P&C drawings. The original scope of work for the engineering design vendor did not include these multiple drawing revisions. In addition, due to the location of abandoned cables a duct bank design needed to be revised. Other unforeseen changes include:

    - Eversource contracted Leidos Engineering to provide the engineering design for the Emerald Street rebuild project. This included all engineering to interface with the AZZ metal clad switchgear design. As the project developed, it became clear that fifty-two drawings beyond those originally provided to AZZ would need to be updated by Leidos to allow AZZ to develop their design. This work was outside of Leidos' original scope.

- VHB was contracted to provide the site plans for the project, but the detailed design of the fence and additional retaining wall was not included in either VHBs or Leidos' scope of work. It was agreed to request Leidos to incorporate this into their contract as they had all the site civil drawings under their control.
- Eversource provided AZZ with conceptual P&C application diagrams as part of the bid specification. The intention was that AZZ would take the application drawings provided by Leidos and complete them as part of their scope. However, AZZ did not have the capability to update the application diagrams and Leidos was requested to complete the application drawings. Prior to final payment we will request AZZ credit the cost of completing these drawings.

The estimate for Engineering has also been increased to meet the request for the P&C Engineers on the project team to bring an Owner's Engineer on to the project to review P&C designs.

4) **Construction ($2,434K):** In the September 2017 PAF, the forecasted cost for construction was estimated at $2,379K. The contracted price was higher than forecast due to the complexity of the construction sequence and several unforeseen items that were not captured in the original construction contract scope of work, including:

- Additional exploratory vacuum excavation was required to safely locate live 12.47kV cables and abandoned power and control cables near a proposed new duct bank;
- Winter work caused by delaying the start of construction from September 2018 to January 2019. The delay was required due to internal budget constraints;
- Installation of temporary services for the switchgear and transformers. To test and commission the new switchgear, a temporary service is needed to provide light, HVAC and to power the battery chargers. To prevent damage due to moisture, temporary power to the four heaters in each of the two new transformers is required;
- Additional grounding needed outside the substation fence to avoid potential step and touch issues;
- Because the construction contract was issued using 70% design documents, there was an adjustment to the quantity of materials between the drawings issued for bidding and the final issued for construction drawings. The additional materials also require additional labor for installation;
- Ground heating for soil sampling. The number and location of soil samples for pre-characterization were based on the 70% design drawings and estimated foundation depths. Once detailed foundation drawings were issued, and additional foundations were identified for the line and bus tie breakers, additional samples were needed. Because of the schedule it was necessary to heat frozen ground so that the samples could be taken prior to excavation and soil removal;

- Soil Management & Disposal – during project development, contaminated soils were confirmed relative to planned excavations which increased forecasted soil management and disposal costs. $134K was previously budgeted for soil management; however, this forecast has since been increased to $190K for the preparation of the soil management plan, site inspections during construction and disposal of contaminated soils. Additional contaminants and hazardous materials on site that have been or are expected to be removed or remediated include: Transite pipe, asbestos sheets, asbestos coated wiring, abandoned lead sheathed cable and petroleum contaminated groundwater;
- Lifting & handling – the two transformers were delivered in March 2018 based on the originally planned in-service date of December 2018. With the overall schedule delays the transformers will have to be stored temporarily and moved a second time. The cost to move the new transformers a second time was not anticipated in September 2017. Based on proposals received, $222K is included in the current forecast to move the new transformers from their temporary storage position to their permanent location. This forecast also includes the cost to remove the old transformers and switchgear prior to scrapping; and
- Permitting support – the cost to support the development of the site plans has increased from an estimated $50K in September 2017 to $115K. The increase is due to the addition of a pre-construction sound survey, a ground penetrating radar survey and additional design for the proposed retaining wall. Permitting also includes weekly environmental compliance monitoring during construction which is required to ensure the Contractor is complying with all mandatory environmental legislation and permit requirements. Incremental request $65K.

The current construction forecast also includes $250K for potential future change orders, final landscaping, control building renovations, paving and potential de-watering.

5) **Testing ($1,276K):** The cut-over schedule currently has more than 50 weeks of back-to-back outages which is longer than previously indicated in the schedule issued for bidding purposes. Additionally, the P&C engineering team proposed the use of a load bank to test the polarity and ratio of the current transformers prior to in-service load testing. The rental of the load bank adds to the testing costs and was not anticipated in September 2017. The role of the testing contractor has expanded in recent years, which although reduced the number of unwanted trips, it has resulted in the cost for testing services increasing beyond those anticipated in September 2017.

6) **Commissioning ($351K):** With the complexity of the cut-over sequence, the services of a Lead Commissioning Engineer (LCE) were secured early to assist with construction sequencing, reviewing design documents to ensure constructability, identifying the outage requirements and reviewing testing plans, etc. Bringing the LCE on to the project much earlier in the sequence was not anticipated in the September 2017 PAF. The current forecast has been increased to $601K to cover LCE support prior to construction and during the construction, testing and commissioning phase.

7) **Material (-$1,025K):** The September 2017 forecast for materials was high. There are small increases in the switchgear and transformer costs compared to the 2017 forecast, but these increases are offset by reductions in cable costs and other miscellaneous material cost reductions. Because of the delays to the project, the new transformers have been filled with oil temporarily which incurred an additional $66K for oil and labor.

8) **Removal ($161K):** Since September 2017, the estimate for removal costs has increased to better reflect the amount of material to be removed (switchgear, steelwork, redundant wood poles, transformers and associated oil removal). The original forecast also included a credit of $50K for investment recovery which is no longer anticipated. It is likely to cost more to scrap all the materials than we would recover from salvage costs.

9) **Miscellaneous (-$33K):** The September 2017 forecast included $206K for miscellaneous project charges including employee expenses (accommodation, meals, etc.). The miscellaneous forecast has been reduced at this stage.

10) **Property Tax ($444K):** In September 2017 property taxes were not included in the project estimate. To date, the project has incurred $174K in property taxes with a further $270K estimated through November 2020.

Total incremental request for direct costs **$4,171K**

11) **Indirect costs ($1,455K):** In the September 2017 PAF, indirect costs were forecasted to be $1,824K. To date, the project has incurred $1,709K in adders and is expected to incur an additional $1,570K to the end of the project. The increase is largely driven by the increase in direct costs and a change in E&S rates. Engineering & Supervision (E&S) rates increased from 0.01 which was used in the original estimate to 0.35. This change has a twofold impact on the project; first, the project has incurred E&S loaders at a higher rate than was originally estimated and secondly the higher rate applies to future investment.

12) **AFUDC ($199K):** In the September 2017 PAF, AFUDC charges for the project were originally estimated at $174K. Actual AFUDC charges incurred to date are $55K with an additional $318K forecast for the remainder of the project.

Total incremental request for indirect costs **$1,654K**, resulting in an overall Supplement Request of **$5,824K**.

Please see the previously authorized documents attached.

Supplement Cost Breakdown (Local Costs)

Note: Dollar values are in thousands:

Line item Category	Original Estimate ($K)	New Estimate ($K)	Variance ($K)
1) Internal Labor	128	330	202
2) Project Management	125	187	62
3) Engineering	460	759	299
4) Construction	2,379	4,813	2,434
5) Testing	250	1,526	1,276
6) Commissioning	250	601	351
7) Material	4,829	3,804	(1,025)
8) Removal	385	546	161
9) Miscellaneous	206	173	(33)
10) Property taxes	0	444	444
Total Directs	**9,012**	**13,183**	**4,171**
11) Indirect	1,824	3,279	1,455
12) AFUDC	174	373	199
Total Indirect	**1,998**	**3,652**	**1,654**
Total ($K rounded)	**11,011**	**16,835**	**5,824**

Supplement Cost Summary (Local Costs)

Note: Dollar values are in thousands:

	Prior Authorized	Supplement Request	Total
Capital Additions - Direct	$8,628	$4,009	$12,637
Less Customer Contribution	$0	$0	$0
Removals net of Salvage ____%	$385	$161	$546
Total Direct Spending	$9,013	$4,170	$13,183
Capital Additions - Indirect	$1,824	$1,455	$3,279
AFUDC	$174	$199	$373
Total Capital Request	$11,011	$5,824	$16,835
O&M	$0	$0	$0
Total Request	**$11,011**	**$5,824**	**$16,835**

Note: Dollar values are in thousands:

Total Supplement Request by year view:

Request by Year	Year 2019	Year 2020	Total
Capital Additions - Direct	$2,000	$2,009	$4,009
Less Customer Contribution	$0	$0	$0
Removals net of Salvage ____%	$0	$161	$161
Total Direct Spending	$2,000	$2,170	$4,170
Capital Additions - Indirect	$728	$727	$1,455
AFUDC	$100	$99	$199
Total Capital Request	$2,828	$2,996	$5,824
O&M	$0	$0	$0
Total Request	**$2,828**	**$2,996**	**$5,824**

Lessons Learned

Construction, Testing and Commissioning – The cost estimating process should continue to monitor actual outturn costs for items such as construction, testing and commissioning to ensure that initial cost estimates accurately capture the cost of performing these activities.

Soil Management – Until subsurface investigations are complete, it is difficult to ascertain with any degree of certainty the scope and scale of any potential contamination. If, in the case of Emerald Street, the site is known to have the potential for contaminants then this should be captured during the conceptual design phase of the project and a contingency amount included in the original estimate until the extent of contamination is known. Alternatively, approval should be sought for preliminary engineering which would include test pits, GPR, etc. to more accurately identify the scope of subsurface issues.

Project Management, Engineering Design, etc. – Constructability reviews and additional preliminary engineering will provide a more comprehensive scope at the start of the project which will reduce impacts to the scope and schedule during the project. Minor design changes are inevitable as the project develops, but the more conceptual engineering that can be done prior to full funding approval the fewer cost increases or schedule overruns will occur.

Lifting & Handling – Transformers are often ordered ahead of their need date. While this reduces the risk of material delays, it adds additional costs to projects because the transformers need to be stored temporarily and then subsequently slid or lifted into position. Additionally, if the transformers arrive too early, they must be partially-filled with oil to ensure the insulation does not dry out. This adds additional costs to add and remove the oil and create temporary oil containment while the units are stored. While Substation Engineering orders the transformers, they should always consult the Project Manager regarding the actual date needed.

REDACTED

Operations Project Authorization Form

Date Prepared: 3/21/18	Project Title: Emerald Street S/S Distribution Line Work
Company/ies: Eversource NH	Project ID Number: A18W17
Organization: NH Operations	Class(es) of Plant: Distribution Line
Project Initiator: [redacted]	Project Category: Reliability - Other
Project Manager: [redacted]	Project Type: *Specific*
Project Sponsor: James Eilenberger	Project Purpose: Interconnection of Substation to Distribution System
Estimated in service date: 10/1/19	If Transmission Project: NA
Eng. /Constr. Resources Budgeted? Yes	Capital Investment Part of Original Operating Plan? Yes
Authorization Type: Full Funding	O&M Expenses Part of the Original Operating Plan? Yes
Total Request: $800,000	

Financial Requirements:

Project Authorization

ERM: ______________________________

FP&A: ______________________________

Executive Summary

The Emerald Street Substation in Keene is a 115/12.47 kV distribution substation. An approved major rebuild/replacement project (A14W01) is currently in design with construction slated to begin later in 2018. This distribution line work project is designed to integrate eight new risers needed to transition power from the substation breakers to the distribution circuits. The project will also require some line relocations to align new risers with existing circuitry in addition to the removal of parts of the W14 circuit and other associated equipment.

This work is to be performed in conjunction with the Emerald Street Substation rebuild project A14W01.

Project Costs Summary

Note: Dollar values are in thousands

	Prior Authorized	2018	20__	20__+	Totals
Capital Additions - Direct	$ -	$ 209	$ 437	$ -	$ 646
Less Customer Contribution	-	-	-	-	-
Removals net of Salvage ____%	-	-	27	-	27
Total - Direct Spending	$ -	$ 209	$ 464	$ -	$ 673
Capital Additions - Indirect	-	35	75	-	110
Subtotal Request	$ -	$ 244	$ 539	$ -	$ 783
AFUDC	-	1	1	-	2
Total Capital Request	$ -	$ 245	$ 540	$ -	$ 785
O&M	-	5	10	-	15
Total Request	$ -	$ 250	$ 550	$ -	$ 800

Financial Evaluation

Provide the following financial information (attach additional detail if summarized items are significant or additional information is needed). Note: Dollar values are in thousands

Direct Capital Costs	Year 1	Year 2	Year 3+	Total
Straight Time Labor	9	20		30
Overtime Labor	0	0		0
Outside Services	91	197		288
Materials	109	246		355
Other, including contingency amounts (describe)				
Total	209	464		673

Indirect Capital Costs	Year 1	Year 2	Year 3+	Total
Indirects/Overheads (including benefits)	35	75		110
Capitalized interest or AFUDC, if any	1	1		2
Total				

Total Capital Costs	245	540		785
Less Total Customer Contribution	0	0		0
Total Capital Project Costs	245	540		785

Total O&M Project Costs	5	10		15

Future Financial Impacts:

No future financial impacts are anticipated with this project.

Asset Retirement Obligation (ARO) and/ or Environmental Cleanup Costs (Environmental Liabilities):

An ARO is a current legal obligation to remove or retire property, plant or equipment at some point in the future. Please refer to APS8 or contact Plant Accounting for further detail.

Is there an ARO associated with this project? No

Are there other environmental cleanup costs associated with this project? No

Operations Technical Authorization Form

Technical Justification:

Project Need Statement

There are currently nine circuits that originate from Emerald Street Substation. The new station design creates eight circuits that need to feed the exiting distribution lines. This work is to bring conductors from the load side of the new breakers to distribution circuits located outside the fence and is fundamental to the substation project.

Project Objectives

The goal in designing the new riser locations is to minimize line relocations while integrating the construction cut overs. Most new risers come up directly under existing circuitry, reducing construction costs.

Project Scope

The scope of this project is to bring conductors from the new circuit breakers out to the roadside distribution circuits. Eight new risers are to be installed for the new circuitry. Nine existing risers are to be removed. A portion of the W14 circuit is to be removed and the W9 circuit will be adjusted to put it in line with the new riser location. There will also be some other minor line adjustments.

Background / Justification

The interconnection of the new circuitry to the distribution lines was anticipated from the beginning of the substation rebuild project. The layout of the substation get away cables and location of the new risers could not be confirmed until significant substation design was completed. A decision was made early in the process to keep the distribution line work project separate from the substation construction process due to planning, accounting, and construction reasons.

Business Process and / or Technical Improvements:

Cost Estimate and Assumptions

Ten separate Storms jobs and estimates were created for the distribution line work outside the substation for each aspect of this project. These jobs have been fully written utilizing the assumptions within our project writing system. Estimates were developed for the underground conduits and cable work from the circuit breakers to the risers by the substation design team and provide to field engineering for inclusion in the PAF.

Alternatives Considered with Cost Estimates

The best riser locations were chosen to reduce line construction and substation design costs. No feasible alternatives were identified.

Project Schedule

Describe the project schedule and milestones. Include estimated start and end dates.

Milestone/Phase Name	Estimated Completion Date
Completion of project	10/1/2019

Regulatory Approvals

All regulatory requirements associated with this project were covered through the larger Emerald Street Substation approval process.

Risks and Risk Mitigation Plans

This project will need to work in conjunction with the Emerald Street Substation construction project. Timing will be driven by the progress of the larger project.

One-Line Diagrams, Attachments,

REDACTED

[redacted]

REDACTED

[redacted]

EVERSOURCE ENERGY

SYSTEM PLANNING & STRATEGY
NEW HAMPSHIRE

Rochester 4.16 kV
Distribution System Study

January, 2017

Approved: Russel D. Johnson

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Table of Contents

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Executive Summary

This study looks at the Twombley Street, Signal Street and Portland St. Substations and other associated electric facilities in the Rochester downtown area. The 4.16 kV distribution system serves most of the central core of the city and is fed by Twombley Street, Signal Street, and Portland Street Substations, serving approximately 5,210 Eversource customers. The Rochester area historically has seen a 1.5% - 2.5% load growth.

This study is driven by obsolescence of equipment at Twombley Street and Signal Street Substations. The Signal Street transformer, 28H1, is the sister unit of the failed units that were at Franklin and Community Street Substations. An additional consideration is the Portland Street transformer 34W3 is above 97% of nameplate rating.

There are multiple limitations to circuit construction in Rochester. The Spaulding Turnpike and Cocheco River run though the city. These obstructions require crossings to reach the other side which increases the difficulty of constructing new lines.

In 2010, the 4.16 kV, 3,750 kVA transformer at Portland St. failed. The transformer was replaced with a 34.5 – 12.47 x 4.16 kV, 6,250 kVA dual voltage transformer. The goal was to temporarily maintain the 4.16 kV system while planning for 12.47 kV system in the future. The 12.47 kV conversion would occur at the time Signal St. and Twombley St. needed to be replaced. There are also multiple 12.47 kV lines in the downtown area that could be used for circuit ties to increase reliability.

It is recommended that Eversource replace Twombley St. with a 12.47 kV, 12.5 MVA transformer and substation, and retire the Signal St. substation. It is also recommended that the downtown area of Rochester be converted from 4.16 kV to 12.47 kV which will take several years to complete. This would create multiple circuit ties between Twombly St. substation on the west side of downtown Rochester and Portland St. substation on the east side of downtown Rochester. The available capacity would be increased, and would eliminate aging equipment. This solution allows for future growth while optimizing the potential for Distribution Automation which would increase system reliability in the downtown Rochester area.

I. Introduction

The downtown Rochester area is primarily served by three, 34.5 - 4.16 kV substations, Twombley Street substation on the west side of the downtown, Signal Street substation in the center of the downtown and Portland Street on the east side of the downtown (see an area map - Appendix A).

Twombley Street substation has one circuit (43H1) supplying the west side of the downtown. The Signal Street substation has two circuits (28H1 and 28H2). The 28H2 circuit supplies a primarily commercial/industrial area in the northern part of the downtown. The 28H1 supplies the central area of the downtown. This circuit ties to the 43H1 circuit thru a cable through the Cocheco River. The Portland Street substation has two 4.16 kV Circuits (34H1 and 34H2). The 34H1 supplies the eastern part of the downtown area. The 34H2 supplies part of the central downtown and has a tie to the 28H1 at Signal Street. (see the circuit map - Appendix B).

II. Study Background

Both the Twombley Street and Signal Street transformers are over 55 years old which is beyond their useful life.

The Signal Street transformer has two other sister units on the Eversource system (Franklin and Community Street) that have recently failed.

The Portland Street 34.5 - 4.16 kV transformer (TB341) has already failed and has been replaced. This transformer has been replaced with a dual voltage 34.5 - 4.16X12.47 kV unit. This was done to allow for future the downtown system to be converted to 12.47 kV.

Portland Street also has two 12.47 kv circuits supplied from two separate 34.5 – 12.47 kV transformers. The 34W4 supplies the area to the north and ties to the 39W1 circuit from the North Rochester substation. The 34W3 supplies load in the southeast of the Rochester downtown. This circuit is loaded to over 97% of the transformer nameplate rating.

III. System Analysis

Area Problems & Limitations

Obsolescence – The equipment at Twombley St. and Signal Street Substations are over 55 years old. The age is based off of the average age of transformers, switchgear, breakers and regulators as shown below in Table 3.1.

The Signal Street transformer is the sister unit of transformers at Franklin and Community Street Substations that have recently failed.

Useful life expectancy is typically 55 years for distribution substation equipment, while only 35-40 years is the expected for cables.

SUBSTATION	EQUIPMENT	POSITION	MANUFACTURER	YEAR	AGE
Twombley St.	Transformer (2.8 MVA)	43H1	Westinghouse	1961	55
Signal St.	LTC Transformer (3.75 MVA)	28H1	Allis Chalmers	1954	62
Portland St. (4kV)	LTC Transformer (6.25 MVA)	TB341	Niagara Transformer	2009	6
Portland St. (12kV)	LTC Transformer (5.25 MVA)	34W3	General Electric	1967	49
	LTC Transformer (5.25 MVA)	34W4	General Electric	1966	50

Table 3.1 - Equipment ages

Loading – Loading on the Twombley Street transformer is over 91% of its nameplate rating. Additionally the 34W3 transformer is loaded to over 96% of its rating. (see table 3.2)

SUBSTATION	EQUIPMENT	PEAK LOAD	PEAK MONTH	NORMAL RATING
Twombley St.	Transformer – 43H1	2.55 MW	Aug 10	2.80 MVA
Signal St.	LTC Transformer – 28H1	2.30 MW	Aug 13	3.75 MVA
Portland St. (4kV)	LTC Transformer – TB341	2.68 MW	Aug 11	6.25 MVA
Portland St. (12kV)	LTC Transformer – 34W3	5.02 MW	Aug 13	5.25 MVA

Table 3.2 – Transformer loading

Natural load growth is expected to cause some lines to reach their normal rating within five years. Also, various lines on the 4.16 kV are expected to have low voltage conditions during peak load under their current configuration. Additional load growth on the circuits reduces the remaining load capacity.

Protection Coordination – During the summer peak load periods and during the time when the Rochester Fair is being held, when the circuit load is higher, the protection coordination at the end of the 28H1 circuit is lost and the only circuit protection is back at the Signal Street substation breaker. Coordination could be improved by converting the 28H1 to a higher voltage. Improved protection coordination would also improve the reliability.

IV. Solution Options

Three solutions to address the Rochester area needs were developed.

1) Rebuild the 4.16kV Substations at Twombley St. and Signal St.
2) Build a 12.47kV Substation at Twombley St.
3) Convert downtown to 34.5kV

These options also include construction restrictions in the downtown area. A new roundabout is being planned for the intersections of Walnut, Washington and North Main streets and it is expected that any new construction may be restricted in this area. (See appendix C for a breakdown of cost estimates).

Option 1: Rebuild the 4.16 kV Substations at Twombley St. and Signal St. – ($7,950,000)

- Rebuild the existing 34.5 – 4.16 kV substations at Twombley Street and Signal Street with 6.25 MVA transformers.
- Build a second circuit from Twombley Street substation.

Positives

- Minimal line work would be required.
- Allows for construction with existing equipment remaining in service.

Negatives

- Loss of a single substation transformer results in isolated load.
- Does not help the protection coordination problem on the 28H1 circuit.
- Requires capacitor banks and voltage regulators to address future low voltage issues.
- Unable to utilize existing 12.47 kV circuits for contingencies and load swapping.
- Does not help offload the 34W3 at Portland St.

Option 2: Build a 12.47 kV Substation at Twombley St. – ($9,194,500)

- Construct a new 34.5 – 12.47 kV substation at Twombley Street with a 12.5 MVA transformer and two 12.47 kV circuits.
- Convert the 4.16 kV downtown to 12.47 kV
- Retire Signal Street substation.

Positives

- Allows for recovery of all load for a single contingency.
- Conversion of downtown allows for future load growth.
- Increases the number of possible circuit ties with other 12.47 kV circuits in the area.
- Utilize new circuit ties along with distribution automation to improved reliability
- Allows for offloading the 34W3 at Portland St. without additional new line construction.

Negatives

- Requires line work to convert the majority of 4.16 kV system to 12.47 kV.

Option 3: Convert Downtown to 34.5 kV – ($8,419,500)

- Convert the current 4.16 kV downtown circuits to 34.5 kV.
- Create 34.5 kV ties between the new 34.5 kV circuits
- Retire the existing substations at Twombley St. and Signal St. Substations.

Positives

- Eliminates the need for additional transformation in downtown Rochester.
- Allows for construction with existing equipment remaining in service.
- Conversion of downtown allows for greater future load growth.

Negatives

- Converts the downtown area to 34.5 kV which is undesirable.
- Leaves no backfeed capability for the existing 12.47 circuits out of Portland St. Substation.
- Would require additional conversion to help offload the 34W3 at Portland St.

Other Options Considered Implausible

The following options were not studied in detail due to implausibility. The projects and reasons for not being considered are described below.

Option 4: Distributed Generation

Since base case loading is not an issue and distributed generation does not address obsolescence, distributed generation was not considered.

Option 5: Conservation and Load Management

For the same reasoning that distributed generation in Option 4 was not considered, the same holds for conservation and load management programs as well.

Option 6: 115 – 12.47 or 4.16 kV Substation at Rochester

Replacing Twombley St. and Signal St. Substations with a 115 kV connected substation would be extremely costly. In addition the substation would need to be placed at Rochester and additional highway crossings would be needed. The cost is too significant for the amount of load that would be served by the substation and is unnecessary.

Option7: Build a 12.47 or 4.16 kV Substation at Signal St.

Retiring Twombley St. and building a substation at Signal St. is not a plausible option. A substation at Signal St. does not allow for backfeeding any of the circuits west of Signal St. This configuration also reduces the number of available circuit ties with Portland St. Substation when compared to the Twombley St. option.

V. Recommendations

Option 1, option 2 and option 3 would all address the loading in the downtown area. Option 1 would maintain the existing 4.16 kV system which would leave a mixture of 4.16 and 12.47 kV circuits. This will allow for switching between the 4.16 kV circuits but would leave a single 12.47 kV circuit with no backup during a contingency.

Option 2 would create a 12.47 k system between two substations (Twombley Street and Portland Street). This will allow for switching flexibility, for the use of distribution automation and resolve the protection coordination. This option would also provide for offloading the 34W3 circuit.

Option 3 would require creating 34.5 kV ties in the downtown area. This would also leave an isolated 12.47 kV circuit with no ties and reduce the reliability.

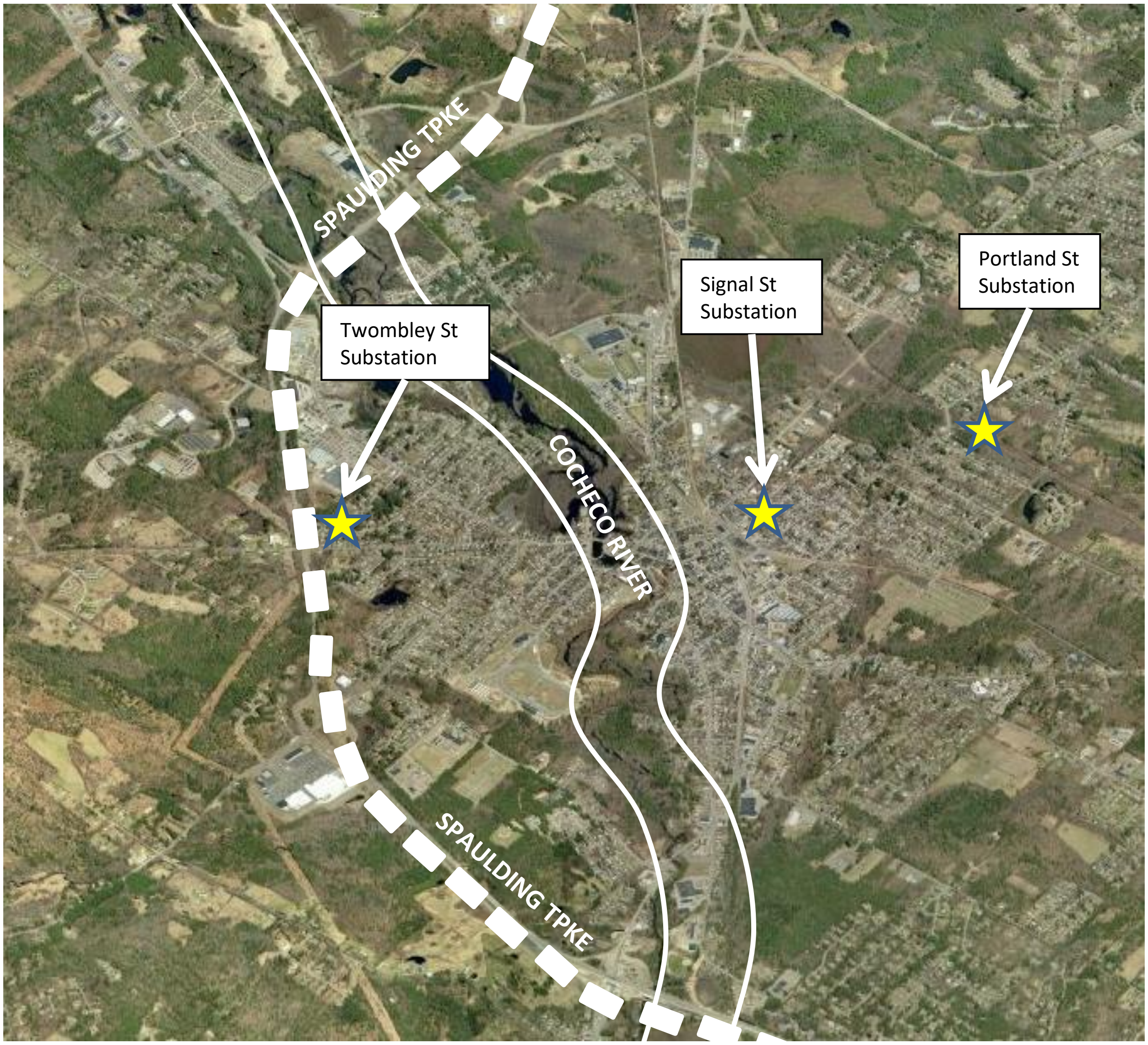
Based on the information contained in this report, it is recommended that Eversource select Option 2, Build new 12.47 kV substation at Twombley St. and retire Signal St (refer to appendix F – Decision Matrix). This Option includes:

1. Convert the Rochester downtown area from 4.16 kV to 12.47 kV with increased circuit ties to accommodate the use of distribution automation.
2. Switch TB341 over to 12.47 kV
3. Install a 3 phase segment down Walnut St. for a second Twombley St. circuit and create a tie to the Portland St. 34W3 circuit.
4. Build a new 34.5 – 12.47 kV substation at Twombley Street.

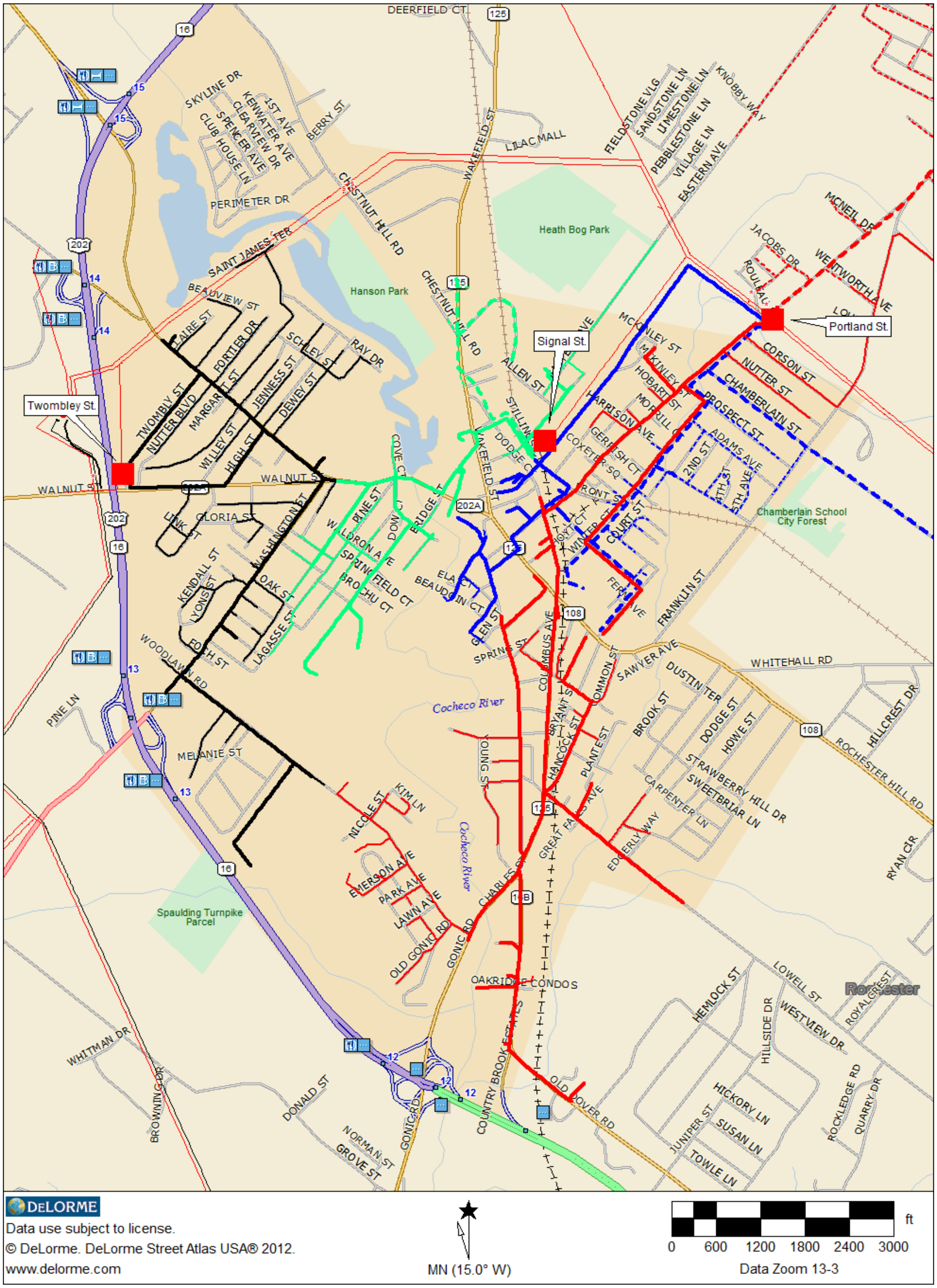
As part of an ongoing Reliability Enhancement program (REP), aging 4.16 kV substations are being retired and the system is being converted to a 12.47 kV when practicable. For outages in the downtown Rochester area the system would be able to be switched between two 12.47 kV substations, Twombley Street and Portland Street (see Appendix E – Proposed System Map and One-Line). Additionally, the use of Distribution Automation would increase reliability and minimize the number of customers affected.

With an existing 12.47 kV substation at Portland Street on the east side of Rochester, and an additional 12.47 kV substation at Twombley Street on the west side of Rochester, this would provide a firm capacity of 16,750 kVA of transformation. This system will also increase reliability by allowing for increased use of distribution automation with four 12.47 kV circuits between two substations.

Appendix A: Downtown Rochester - Area Map

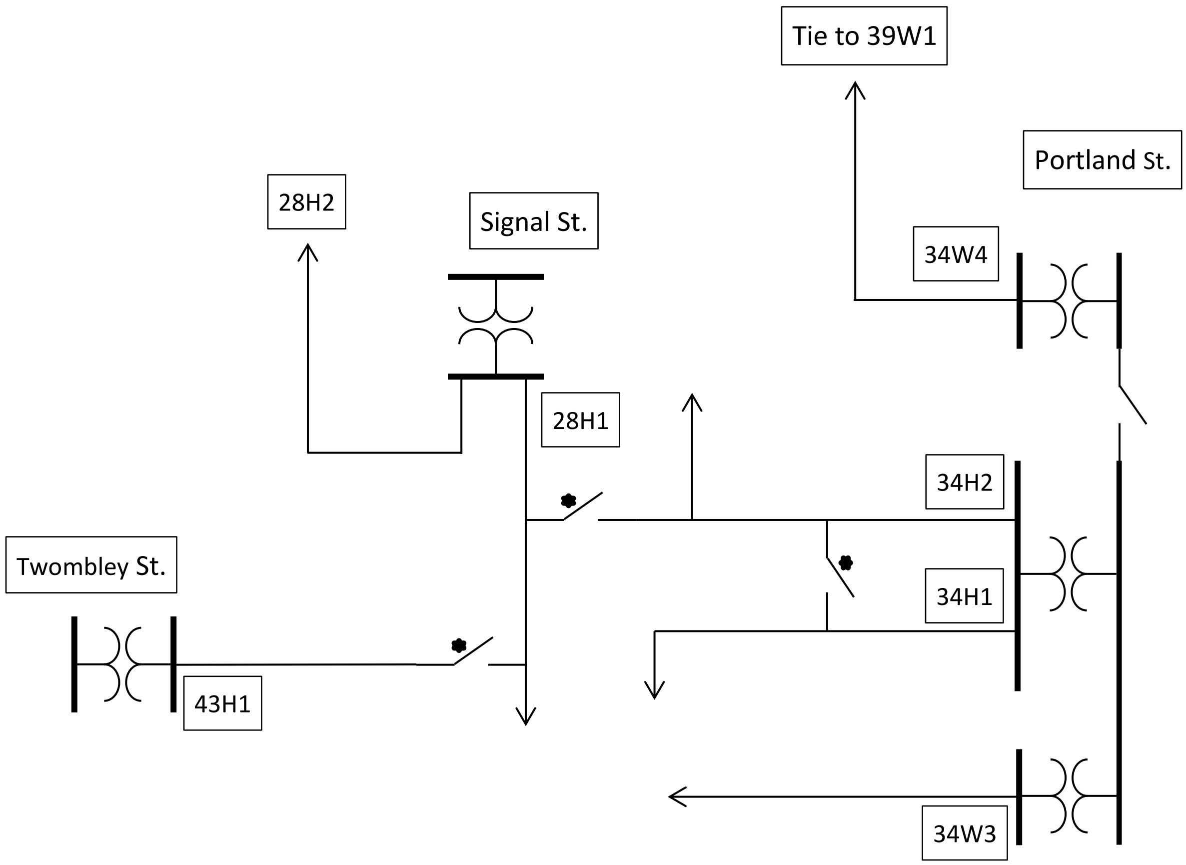


Appendix B: Downtown Rochester - Circuit Map & One-Line



Circuit map of Downtown Rochester Black=43H1, Green 28 H1, 28H2, Blue 34H1, 34H2, Red=34W3, 34W2

The following is a one-line of the downtown Rochester electric system



Appendix C: Option Cost Estimates

Option 1: Build a 4.16 kV Substation at Twombley St. and Signal St. – $7,950,000

- Construction of an open-air 34.5-4.16 kV substation at Twombley St. with one 6.25 MVA transformer and three breakers. ($3,500,000)
- Construction of an open-air 34.5-4.16 kV substation at Signal St. with one 6.25 MVA transformer and three breakers. ($3,500,000)
- Install a short 3 phase segment down Walnut St. for a second Twombley St. circuit ($50,000)
- Distribution line work to remove thermal and voltage violations. ($800,000)
- Retirement of existing Twombley St. and Signal St. Substations. ($100,000)

Option 2: Build a 12.47 kV Substation at Twombley St. – $9,194,500

- Convert Portland St 34H1 ($1,279,000)
- Build 12.47 kV from Lowell St (34W3) to Washington St (43H1) ($808,000)
- Convert 43H1 to 12.47 kV and take Twombley Street substation out of service ($1,066,000)
- Build a new 34.5-12.47 kV, substation at Twombley Street with one 12.5 MVA transformer and three breakers ($3,500,000)
- Convert 28H1 and 28H2 from Signal St to Rochester URD. ($1,057,000)
- Complete the conversion of downtown Rochester and retire Signal St. ($1,484,500)

Option 3: Retire Twombley and Signal St., Convert Downtown to 34.5 kV – $8,419,500

- Convert Portland St 34H1 ($1,712,000)
- Build 34.5 kV from Lowell St (34W3) to Washington St (43H1) ($2,923,000)
- Convert 43H1 to 34.5 kV and take Twombley Street substation out of service ($1,066,000)
- Convert 28H1 and 28H2 from Signal St to Rochester URD. (6, $1,057,000)
- Complete the conversion of downtown Rochester and retire Signal St. ($1,484,500)
- Convert the Rochester URD to 34.5 kV. ($77,000)
- Retire Twombley St. and Signal St. substations ($100,000)

Appendix D: Property Information

Portland Street Substation

Figure D.1 – Aerial and parcel maps of the Portland Street Substation, property highlighted in yellow.

Property Information:

Address: 483 Portland St. Rochester, NH — Total Acres: 5.9

Wetlands: None — Land Value: 86600

Property adjacent to Portland Street Substation

Figure D.2 – Aerial and parcel maps of the property adjacent Portland Street Substation, property highlighted in yellow.

Property Information:

Address: 470 Portland St. Rochester, NH — Total Acres: 2.7

Wetlands: Minimal — Land Value: 71800

Signal Street Substation

Figure D.4 – Aerial and parcel maps of the Signal Street Substation, property highlighted in yellow.

Property Information:

Address: 23 Signal St. Rochester, NH
Wetlands: None
Total Acres: 1.96
Land Value: 68800

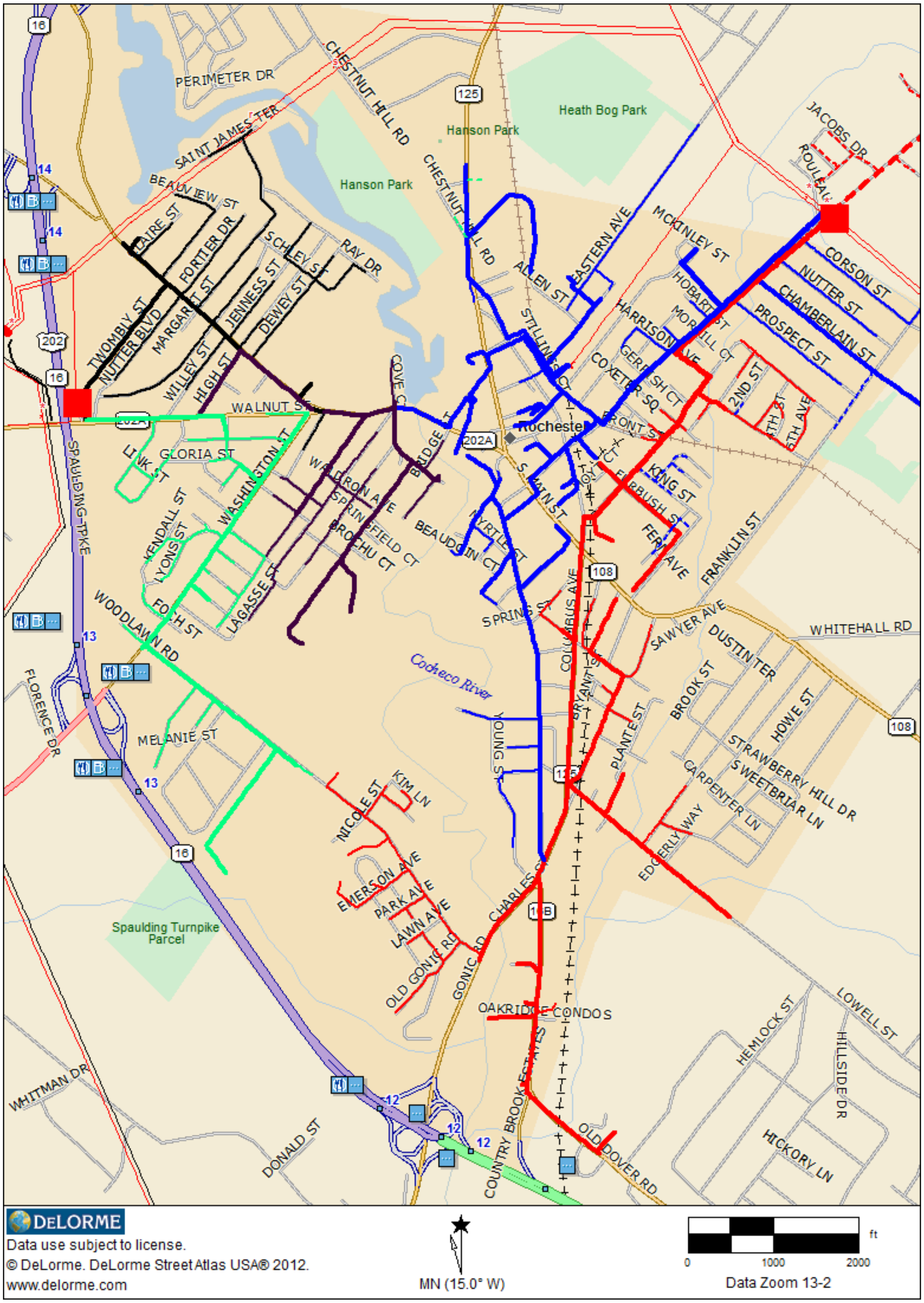
Twombley Street Substation

Figure D.5 – Aerial and parcel maps of the Twombley Street Substation, property highlighted in yellow.

Property Information:

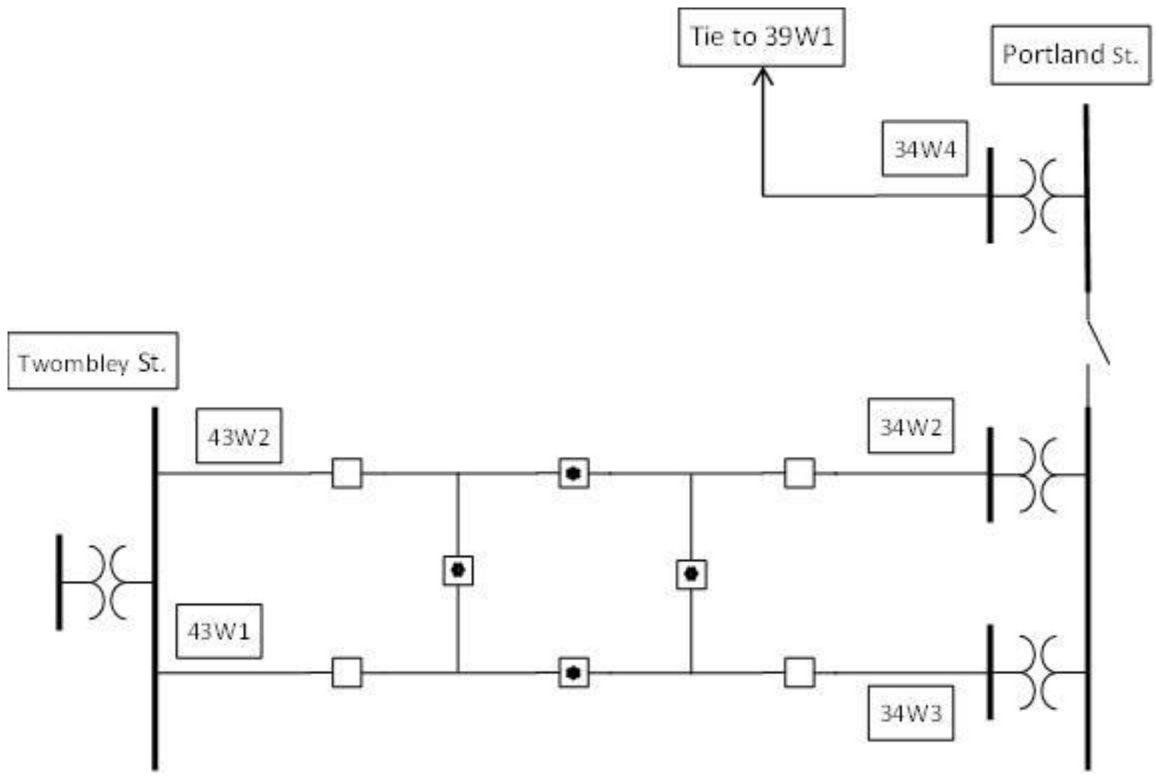
Address: 33 Twombley St. Rochester, NH
Wetlands: Significant
Total Acres: 0.7
Land Value: 63800

Appendix E: Proposed System Map and One-Line



Proposed circuit map of Downtown Rochester Black=43W2, Green 43W1, Blue 34W2, Red=34W3

The following is a proposed one-line of the downtown Rochester electric system



Appendix F: Decision Matrix for Proposed Downtown Rochester Options

	Weight	Rating 4-5 = Superior, 2 -3 = Adequate, 0-1= Inferior		
		Option 1: 4kV S/S at Twombley St. & Signal St.	**Option 2:** 12kV S/S at Twombley St.	**Option 3:** Convert to 34kV
Addresses ED-3002 Design Criteria	8	3	3	3
Addresses Area Load Growth (Long Term, 10 Years)	8	1	5	5
Improves Reliability: SAIDI	8	0	5	2
Net Present Value (2015) [1]	7	4	2	3
Environmental Impact	5	3	3	4
Contingency Solution	5	0	5	3
Power Quality Improvement (SARFI-70)	4	4	4	2
Operating Cost	3	2	3	4
System Loss Savings	3	1	4	4
Total		100	195	168

Note 1: Since the implementation of the five options would occur at the same time, the net present value was not calculated. The total cost estimate in 2016 dollars was compared directly.

Technical Authorization Form

#NH-170015-DS

Date Prepared: January 11, 2017	Project Title: Rochester 4 kV Distribution System Upgrade
Company/ies: Eversource, NH	Project ID Number: A17E01
Organization: NH Operations	Class(es) of Plant: Distribution
Project Initiator: [redacted]	Project Category: Substation / Distribution Lines
Project Owner/Manager: Russel Johnson	Project Type: *Specific*
Project Sponsor: Jim Eilenberger	Project Purpose: part of regulatory tracked program? No
Estimated in service date: November 1, 2019	If Transmission Project: *NA*
Authorization Type: *Conceptual Engineering*	Authorization Amount: $400,000 for Engineering

Project Need Statement *(Description of Issue)*

This requested authorization is for writing the line conversion construction, surveying the substation property and preliminary substation engineering.

The Signal St. transformer sister units (Community Street and Franklin) have recently failed. The 4.16 kV circuit (28H1) out of Signal Street is overloaded during summer peak load conditions. Because of heavy loading at the end of the 28H1 circuit, fuse coordination is lost and the only circuit protection is back to the substation breaker. This will cause an outage to the entire circuit for a fault near the end of the circuit. The Twombley Street transformer was been loaded to 91% during the summer of 2014 and up to 135% at other times of the year during underground failures of the 28H1. The Portland Street 34W3 transformer loading reached 97% in the summer of 2016.

Project Description

- The electrical system in downtown Rochester consists of three 4.16 kV substations:
  - Twombley St. (43H) – 2,800 kVA, 55 years, loaded to 91% nameplate, located on the west side of the downtown
  - Signal St. (28H) – 3,750 kVA, 62 years, loaded to 61% nameplate, located in the center of the downtown
  - Portland St. (34H) – 6,250 kVA, 7 years, located on the east side of the downtown (this transformer recently failed and was replaced with a dual voltage 4.16/12.47 kV unit for future use at 12.47 kV).
- There are 5, 4.16 kV circuits (43H1, 28H1, 28H2, 34H1 and 34H2) in downtown Rochester.
- There are 2 additional 12.47 kV circuits from Portland St. (34W3 and 34W4). (see Figure 1).

The proposed project eliminates Signal Street S/S, replaces Twombley St S/S with a 12.47 kV 12.5 MVA substation, and converts the line voltage in the area from 4kV to 12.47 kV.

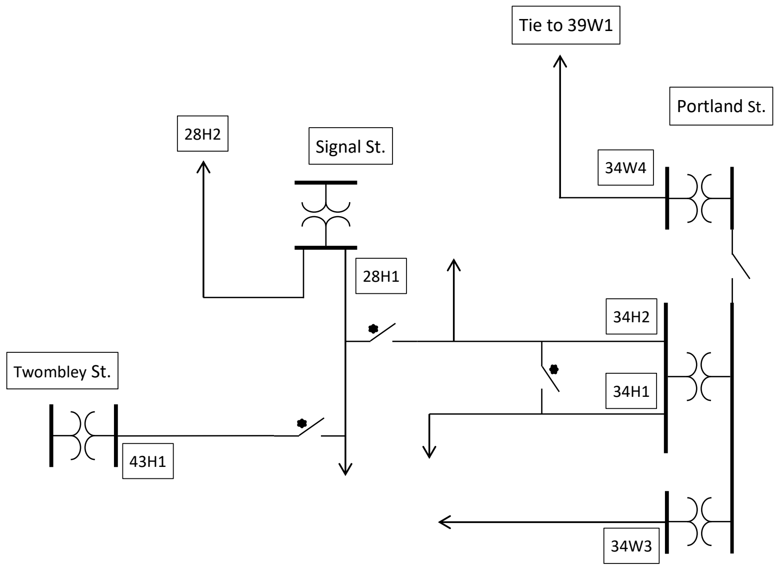


Figure 1

Project Objectives

This project will upgrade the distribution system in the city of Rochester including the following:

- Retire a 62 year old Signal St. substation transformer
- Create a 12.47 kV interconnected system between Portland St and Twombly St substations.
- Increase switching flexibility between two, 12.47 kV substations (Portland St and Twombley St.).
- This increased switching flexibility and substation capacity will allow for the increased use of distribution automation to increase reliability
- Improve the protection margins of the distribution system to improve system reliability.

Project Scope

Phase 1 – Convert the 34H1from 4.16 kV to 12.47 kV

- Install new spacer cable from Portland St. substation down Portland St. to School St. then south on Winter St.to Columbus Ave.
- Step and convert 34H1 4.16 kV load as needed
- Change the transformer voltage on (TB341) at Portland St from 4.16 kV to 12.47 kV

Phase 2 – Build a new 12.47 kV line from 34W3 to 43H1

- Extend 3-phase, 34W3 up Brock St. to 43H1 (0.5 mi)

Phase 3 – Convert 43H1

- Convert 43H1 from 4.16 kV to 12.47 kV along Brock St., Washington St., Roy St. and Walnut St. to Twombley St. substation (1.5 mi)
- Feed remaining 43H1 load from steps off the 340 line at North Main St.

Phase 4 – Substation Construction

- Take Twombley St. substation out-of-service and build a new 12.47 kV substation with a 34.5 kV breaker and three 12.47 kV breakers (1 transformer breaker and 2 line breakers)

Phase 5 – Convert 28H1

- Convert the remaining 4.16 kv, 28H1 circuit in Downtown Rochester

Phase 6 – Complete Conversion

- Continue 4.16 kv conversion on 43H1, 28H1, 34H1 & 34H2
- Retire Signal Street substation

Resulting proposed one-line is provided at back of TAF.

Background / Justification

- The Signal St. transformer is 62 years old and is loaded to 61% of nameplate. The sister units in Berlin and Franklin have also recently failed
- The Twombly St. transformer is 55 years old and is loaded to 91% of nameplate
- The 4.16 kV 28H1circuit is overloaded to the point where circuit fusing is overloaded during peak times and the only protection is the substation breaker.
- An interconnected 12.47 kV system will increase reliability by creating new circuit ties between Portland St. and Twombley St. substations and allow for the use of distribution automation.

Business Process and / or Technical Improvements:

This project will improve the reliability of the distribution system in the city of Rochester. The imminent failure of a 62 year old transformer with sister units that have already failed will be eliminated. The reliability of the underlying distribution system will be improved by converting the system to a 12.47 kV voltage which will improve the protection margins and provide the ability to utilize distribution automation to effectively minimize the customer impact of unexpected outages.

Cost Estimate and Assumptions

Phase 1	Convert Portland St. 34H1	$1,279,000
Phase 2	Build 12.47 kv from 34W3 to 43H1	$808,000
Phase 3	Convert 43H1 to 12.47 & take Twombley St. out-of-service	$1,066,000
Phase 4	Build a new 34.5-12.47 kV substation at Twombley St.	$3,500,000
Phase 5	Convert 28H1from Signal St.	$1,057,000
Phase 6	Complete conversion & retire Signal St. substation	$1,484,500
Total		$9,194,500

Alternatives Considered with Cost Estimates

Alternatives Considered:

1) Build a 4.16 kV Substation at Twombley St. and Signal St. $7,950,000
2) Retire Twombley and Signal St. , Convert downtown to 34.5 kV $8,419,500

For a discussion of the options and the decision matrix, refer to the Rochester 4.16 kV Distribution System Study – January 2017 (see reference section of this TAF for the location of this report).

Project Schedule

Describe the project schedule and milestones. Include estimated start and end dates.

Milestone/Phase Name	Estimated Completion Date
Project Approval	02/01/17
Engineering	09/01/17
Phase 1 - Convert Portland St. 34H1	12/01/17
Phase 2 - Build 12.47 kv from 34W3 to 43H1	03/01/18
Phase 3 - Convert 43H1 to 12.47 & take Twombley St. out-of-service	06/01/18
Phase 4 - Build a new 34.5-12.47 kV substation at Twombley St	06/01/18
Phase 5 - Convert 28H1from Signal St.	04/01/19
Phase 6 - Complete conversion & retire Signal St. substation	11/01/19
In-Service date	11/01/19

Regulatory Approvals
Permitting as required by the City of Rochester and the State of New Hampshire

Risks and Risk Mitigation Plans
Equipment failure (i.e. transformer) during construction may require the use of a mobile substation.

References
For a detailed description of this project, refer to the 'Rochester 4.16 kV Distribution System Study – January 2017'

One-Line Diagrams, Attachments, and Images

Proposed ultimate one-line of the Rochester interconnected 12.47 kV system between Portland St. and a new Twombley St. substations.

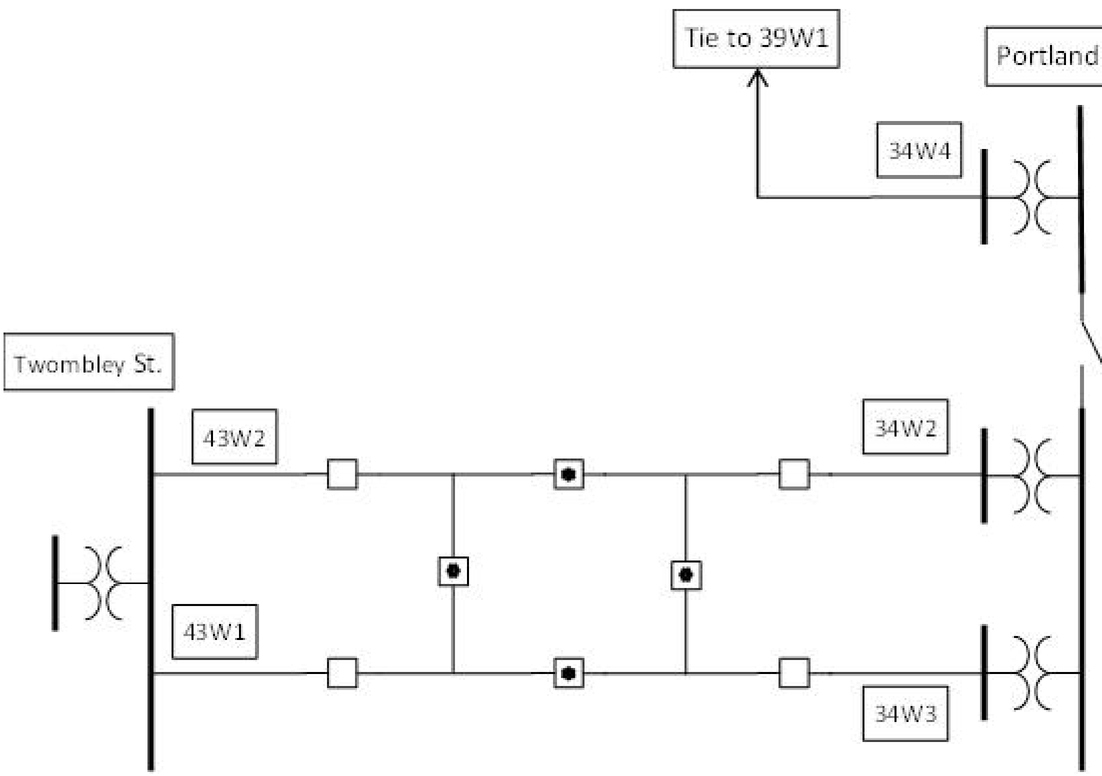


Figure 2

Operations Project Authorization Form

Date Prepared: 2/28/2018	**Project Title: Rochester 4kV Conversion**
Company/ies: Eversource NH	**Project ID Number: A17E09**
Organization: NH Operations	**Class(es) of Plant: Distribution**
Project Initiator: [redacted]	**Project Category: Reliability - Distribution Lines**
Project Manager: Russel Johnson	**Project Type: Specific**
Project Sponsor: James Eilenberger	**Project Purpose: Improve Reliability, Eliminate 4 kV S/S**
Estimated in service date: 6/1/2021	**If Transmission Project: PTF? n/a**
Eng. /Constr. Resources Budgeted? Yes	**Capital Investment Part of Original Operating Plan? Yes**
Authorization Type: Full Funding	**O&M Expenses Part of the Original Operating Plan? Yes**
Total Request: $5,236,000	

Financial Requirements:

Project Authorization

ERM: ______________________________

FP&A: ______________________________

Executive Summary

This request is for full funding in the amount of $5,236,000 for the project described. This project was approved for $100,000 for Engineering on 3/9/17 by the NH Technical Review Committee.

This project will improve the reliability of the distribution system in the city of Rochester by converting three 4 kV circuits to 12.47 kV, establishing new circuit ties between four 12.47 kV circuits in Rochester and allow for the use of distribution automation.

This project includes the conversion of the distribution system in downtown Rochester from 4.16 kV to 12.47 kV. The 34.5-4.16 transformer at Portland Street substation that feeds a portion of the downtown distribution system failed recently. This transformer was replaced with a 4.16/12.47 kV dual voltage transformer. When the conversion takes place, this transformer will be switched to 12.47 kV to feed a portion of the downtown 12.47 kV system.

The 34.5-4/16 kV substation at Twombley Street substation will be replaced with a new 34.5-12.47 kV substation to feed the remaining downtown distribution system. The Twombley Street substation replacement is estimated for $2,000,000 and will be done with a separate substation project authorization. The remaining 4.16 kV distribution system will then be converted to 12.47 kV.

After the downtown is converted to 12.47 kV, the 34.5-4.16 kV substation at Signal Street will be retired.

When completed, there will be two circuits from Twombley Street and two circuits from Portland Street these circuits will be tied together with normally open automated devices (see one-line in the attachment section).

Project Costs Summary

	Prior Authorized	2018	2019	2020+	Totals
Capital Additions - Direct	$ 100	$ 1,409	$ 640	$ 1,842	$ 3,991
Less Customer Contribution	-	-	-	-	-
Removals net of Salvage ____%	-	16	75		91
Total - Direct Spending	$ 100	$ 1,425	$ 715	$ 1,842	$ 4,082
Capital Additions - Indirect	-	554	153	441	1,148
Subtotal Request	$ 100	$ 1,979	$ 868	$ 2,283	$ 5,230
AFUDC	-	4	-	-	4
Total Capital Request	$ 100	$ 1,983	$ 868	$ 2,283	$ 5,234
O&M	-	2	-	-	2
Total Request	$ 100	$ 1,985	$ 868	$ 2,283	$ 5,236

Financial Evaluation

Note: Dollar values are in thousands

Direct Capital Costs	2018	2019	2020+	Total
Straight Time Labor	41	12	5	58
Overtime Labor	1			1
Outside Services	1,024	528	1,333	2,885
Materials	207	88	252	547
Other, including contingency amounts (describe)	152	87	252	501
Total	1,425	715	1,842	3,982

Indirect Capital Costs	2018	2019	2020+	Total
Indirects/Overheads (including benefits)	554	153	441	1,148
Capitalized interest or AFUDC, if any	4	0	0	4
Total	558	153	441	1,152

Total Capital Costs	**1,983**	**868**	**2,283**	**5,134**
Less Total Customer Contribution				
Total Capital Project Costs	**1,983**	**868**	**2,283**	**5,134**
Total O&M Project Costs	2	0	0	2

Note: Explain unique payment provisions, if applicable

Future Financial Impacts:

Provide below the estimated future costs that will result from the project:
Note: Dollar values are in thousands:

Future Costs	Year 20__	Year 20__	Year20__	Year 20__+	Total Future Project Costs
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Describe the estimated future Capital, O&M and/or Other costs noted above:

n/a

What functional area(s) will these future costs be funded in?____________________________________
A representative from the respective functional area is required to be included as a project approver.

<u>If this is other than a Reliability Project, please complete the section below;</u>

Provide below the estimated financial benefits that will result from the project:
Note: Dollar values are in thousands:

Future Benefits	Year 20__	Year 20__	Year20__	Year 20__+	Total Future Project Benefits
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Describe the estimated future Capital, O&M and/or Other benefits noted above:

What functional area(s) will these benefits be reflected in?_____________________________________
A representative from the respective functional area is required to be included as a project approver.

Asset Retirement Obligation (ARO) and/ or Environmental Cleanup Costs (Environmental Liabilities):

Is there an ARO associated with this project? If yes, please provide details: No.

Are there other environmental cleanup costs associated with this project? If yes, please provide details: No.

Technical Justification:

Project Need Statement

The 4.16 kV distribution system (circuit 28H1), which serves the downtown Rochester, is fed by the Signal Street, Twombley Street and Portland Street substations.

The Signal Street substation transformer is over 62 years old and the sister units to this transformer (Community Street and Franklin) have failed in recent years. There are 2 circuits being fed from this substation, 28H1 and 28H2. Because the circuit is heavily loaded, fuse coordination on the 28H1 circuit is lost and the only circuit protection is back to the substation breaker. This results in an outage to the entire circuit for a fault near the end of the circuit.

The Twombley Street transformer is loaded to over 91% of its nameplate rating. A new 12.47 kV transformer at Twombley Street coupled with a change to 12.47 kV at Portland Street S/S will also help to off load the other Portland Street 12.47 kV transformer which is loaded to over 97% of its nameplate rating.

Project Objectives

This project will upgrade the distribution system in the city of Rochester including the following:

- Create a 12.47 kV interconnected system between Portland St and Twombly St substations.
- Increase switching flexibility between two, 12.47 kV substations (Portland St and Twombley Street).
- This increased switching flexibility and substation capacity will allow for the increased use of distribution automation to increase reliability
- Improve the protection margins of the distribution system to improve system reliability.
- Allow for the retirement of the 62-year-old Signal Street substation.
- Provide additional 12kV transformer capacity at Portland Street to support heavily loaded 34W3 transformer.

Project Scope

2018 work scope:

- Reconductor the 34H1 with spacer cable from Portland Street substation down Portland Street to School Street then south on Winter Street to Route 125 (Columbus Ave.) and convert the 4.16 kV to 12.47 kV.
- Reconductor south along route 125 to Brock Street and convert Brock Street to Washington Street

2019 work scope (complete prior to 6/1 to allow Twombley Street substation to be taken out-of-service):

- Convert Washington Street to Twombley Street substation
- Install 3-500 kVA steps on the 340 line and feed 43H1 in the No. Main Street area
- Take Twombley Street substation out of service for construction of a new 12.47 kV substation. (this will be done under a separate substation project authorization)

2020 work scope (to begin after the new Twombley substation goes into service, 6/1)

- Convert 43H1 and remove steps
- Convert 28H1

2021 work scope:

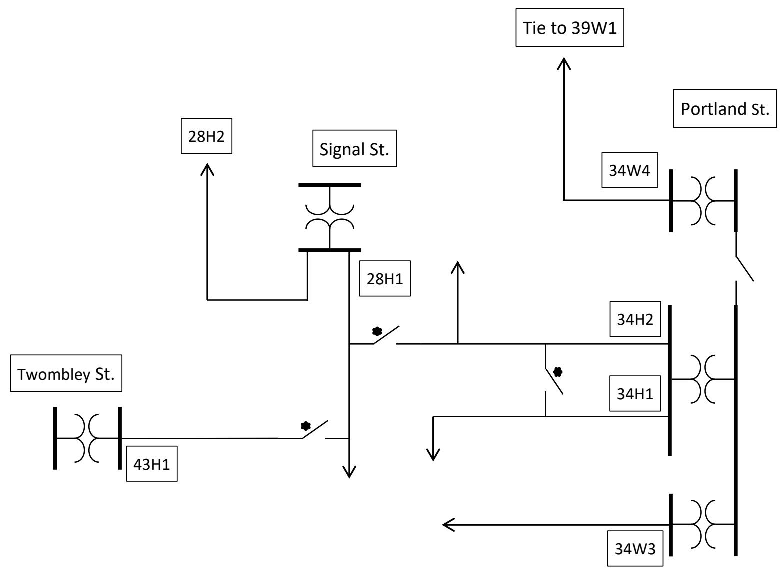
- Convert 28H2
- Convert 34H2

Background / Justification

The electrical system in downtown Rochester consists of three 4.16 kV substations:

- Twombley Street (43H) – 2,800 kVA, 55 years, loaded to 91% nameplate, located on the west side of the downtown
- Signal Street (28H) – 3,750 kVA, 62 years, loaded to 61% nameplate, located in the center of the downtown
- Portland Street (34H) – 6,250 kVA, 7 years, located on the east side of the downtown (this transformer recently failed and was replaced with a dual voltage 4.16/12.47 kV unit and is planned for future use at 12.47 kV).

There are 5, 4.16 kV circuits (43H1, 28H1, 28H2, 34H1 and 34H2) in downtown Rochester. There are 2 additional 12.47 kV circuits from Portland Street (34W3 and 34W4). (See the following diagram.)



The proposed project eliminates Signal Street S/S, replaces Twombley St S/S with a 12.47 kV 12.5 MVA substation, and converts the line voltage in the area from 4kV to 12.47 kV. An interconnected 12.47 kV system will increase reliability by creating new circuit ties between Portland Street and a new 12.47 kV Twombley Street substations and allow for the use of distribution automation. (see attached one-line diagram)

Business Process and / or Technical Improvements:

This project will improve the reliability of the distribution system in the city of Rochester. The imminent failure of a 62-year-old transformer with sister units that have already failed will be eliminated. The reliability of the underlying distribution system will be improved by converting the system to a 12.47 kV voltage which will improve the protection margins and provide the ability to utilize distribution automation to effectively minimize the customer impact of unexpected outages.

Alternatives Considered with Cost Estimates

Alternatives Considered:

1) Build a 4.16 kV Substation at Twombley Street and Signal Street $7,950,000
2) Retire Twombley and Signal Street, Convert downtown to 34.5 kV $8,419,500

For a discussion of the options and the decision matrix, refer to the Rochester 4.16 kV Distribution System Study – January 2017.

Project Schedule

Milestone/Phase Name	Estimated Completion Date
Phase 1 – Reconductor and convert Portland Street 34H1 to 12.47 kV Reconductor and convert a portion of the 43H1 to 12.47 kV	12/01/18
Phase 2 – Convert another portion of the 43H1 to 12.47 kV. Install steps to off load the Twombley Street substation	6/1/19
Phase 3 – Convert the remaining 43H1 to 12.47 kV. Convert the 28H1 to 12.47 kV	12/1/20
Phase 4 – Convert the remaining 4.16 kV circuits (28H2 & 34H2) to 12.47 kV and retire Signal Street substation	12/1/21

Regulatory Approvals

Permitting as required by the City of Rochester and the State of New Hampshire

Risks and Risk Mitigation Plans

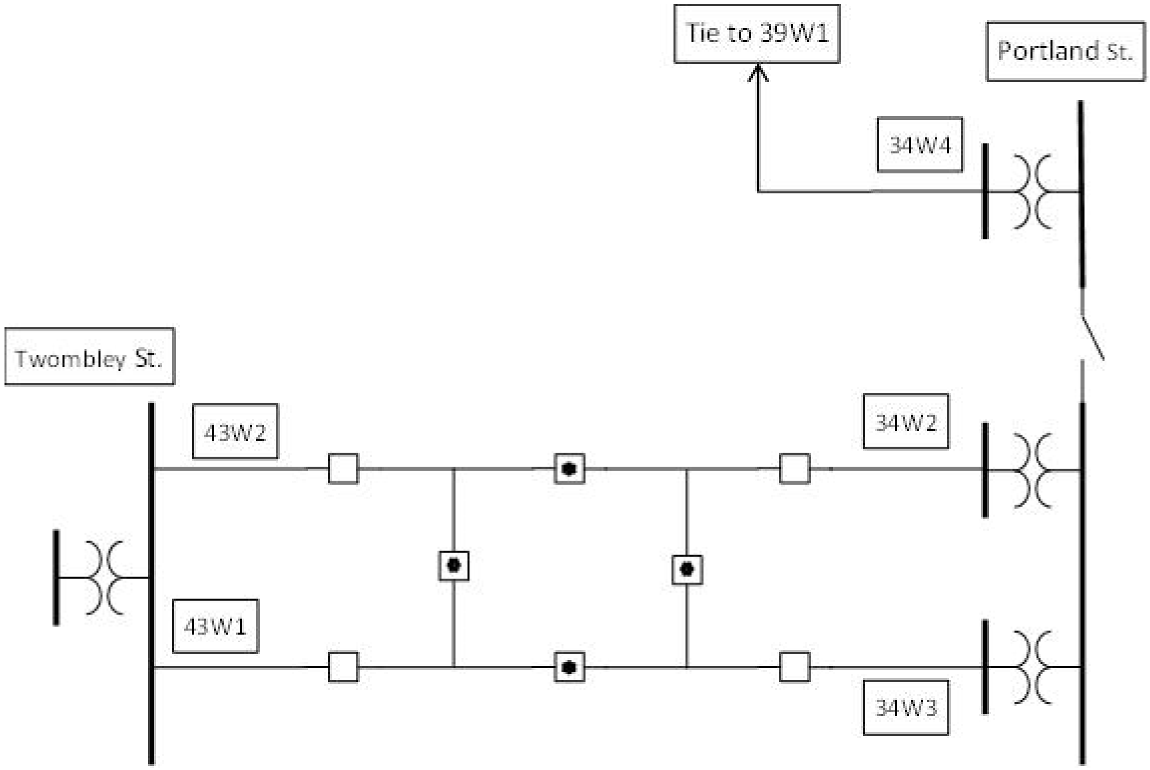
Substation transformer failure before or during construction may require the use of a mobile substation.

References

For a detailed description of this project, refer to the 'Rochester 4.16 kV Distribution System Study – January 2017'.

Attachments (One-Line Diagrams, Images, etc.)

Proposed ultimate one-line of the Rochester interconnected 12.47 kV system between Portland Street and the new Twombley Street substations.


Tie to 39W1
Portland St.
34W4
Twombley St.
43W2
34W2
43W1
34W3

Operations Project Authorization Form

Approved at May 29, 2019 EPAC

Link to Meeting Minutes

Date Prepared: May 13, 2019	**Project Title: Rebuild Twombly Street SS**
Company/ies: Eversource NH	**Project ID Number: A17E05**
Organization: NH Operations	**Class(es) of Plant: Distribution Substation, Distribution Line**
Project Initiator: [redacted]	**Project Category: Stations – Other**
Project Manager: [redacted]	**Project Type: Specific**
Project Sponsor: Russel Johnson	**Project Purpose: Increase reliability and support conversion to 12.47kV**
Estimated in service date: 6/1/2020	**If Transmission Project, PTF/Non-PTF: NA**
Eng. / Constr. Resources Budgeted? Yes	**Capital Investment Part of Original Operating Plan: Yes**
Authorization Type: Full Funding	**O&M Expenses Part of the Original Operating Plan: NA**
Total Request: $6,296K **$5,463K (D SS), $833K (D Line)**	

Financial Requirements:

Project Authorization

ERM: ______________________________

FP&A: ______________________________

Executive Summary

This Project Authorization Form (PAF) requests full funding of $6,296K for the replacement of the existing Twombly Street SS in Rochester, NH. This includes $5,463K for the substation and $833K for the Distribution ROW line. This project was approved for preliminary engineering in the amount of $300,000 on March 16, 2017 in PowerPlan per TAF #NH-170015-DS. Adjacent parcels of land have been acquired and surveyed and a Scope of Work document is complete. Electrical and Civil/Site Engineering are at 70%. The P&C Engineering is being done by a Contractor and has not yet started. $201K has been spent to date through May 14, 2019. Construction is scheduled to begin in 3rd Quarter 2019.

An area study was performed to address load growth and aging equipment in Rochester, NH. This was documented in the Rochester 4.16 kV Distribution System Study – January 2017. The recommendations in this report were to implement several projects to eliminate Signal Street SS, replace Twombly Street SS with a new 12.47kV 12.5 MVA substation, completely remove the existing Twombly Street SS, and convert the line voltage in the area from 4kV to 12.47kV.

This project is for the construction of the new Twombly Street SS, removal of the existing Twombly Street SS, and rebuild of 34.5kV right of way structures to feed the new substation. The distribution 4kV to 12.47kV conversion project (A17E09) was approved on July 2, 2018 for $5,236K. The removal of the Signal Street SS will be a separate annual work order which has not yet been established.

Project Costs Summary (Total Cost)
Note: Dollar values are in thousands

	Prior Authorized	Spent 2017 through 5/14/19	Remaining 2019	2020	Totals
Capital Additions - Direct	$240	$148	$1,359	$2,970	$4,477
Less Customer Contribution	$	$	$	$	$
Removals net of Salvage __%	$	$	$	$113	$113
Total - Direct Spending	$240	$148	$1,359	$3,083	$4,590
Capital Additions - Indirect	$60	$52	$535	$920	$1,507
Subtotal Request	$300	$200	$1,894,	$4,003	$6,097
AFUDC	$0	$1	$51	$147	$199
Total Capital Request	$300	$201	$1,945	$4,150	$6,296
O&M	$	$	$	$	$
Total Request	**$300**	**$201**	**$1,945**	**$4,150**	**$6,296**

Financial Evaluation (Total Cost)
Note: Dollar values are in thousands

Direct Capital Costs	2017-5/14/19	Remaining 2019	2020	Totals
Straight Time Labor	$55	$128	$151	$334
Overtime Labor	$0	$0	$0	$0
Outside Services	$37	$341	$2,055	$2,433
Materials	$56	$770	$682	$1,508
Other, including contingency amounts (describe)	$0	$120	$194	$315
Total Direct Costs	**$148**	**$1,359**	**$3,083**	**$4,590**
Indirect Capital Costs	**2017-5/14/19**	**Remaining 2019**	**2020**	**Totals**
Indirects/Overheads (including benefits)	$52	$535	$920	$1,507
Capitalized interest or AFUDC, if any	$1	$51	$147	$199
Total Indirect Costs	**$53**	**$586**	**$1,067**	**$1,706**
Total Capital Costs	**$201**	**$1,945**	**$4,150**	**$6,296**
Less Total Customer Contribution	$	$	$	$
Total Capital Project Costs	**$201**	**$1,945**	**$4,150**	**$6,296**
Total O&M Project Costs	$	$	$	$

Note: Explain unique payment provisions, if applicable:

Other/Contingency includes: Material & Equipment prices different than estimate ($75K), Severe Weather, Delays, Additional OT to meet schedule ($85K), Detail design differs from conceptual ($120K), Other – permits/fees/taxes/expenses ($35K)

Project Costs Summary (Distribution Substation)

Note: Dollar values are in thousands

	Prior Authorized	Spent 2017 through 5/14/19	Remaining 2019	2020	Totals
Capital Additions - Direct	$240	$148	$1,302	$2,578	$4,028
Less Customer Contribution	$	$	$	$	$
Removals net of Salvage __%	$	$	$	$105	$105
Total - Direct Spending	$240	$148	$1,302	$2,683	$4,133
Capital Additions - Indirect	$60	$52	$436	$667	$1,155
Subtotal Request	$300	$200	$1,738	$3,350	$5,288
AFUDC	$0	$1	$47	$127	$175
Total Capital Request	$300	$201	$1,785	$3,477	$5,463
O&M	$	$	$	$	$
Total Request	**$300**	**$201**	**$1,785**	**$3,477**	**$5,463**

Financial Evaluation (Distribution Substation)

Note: Dollar values are in thousands

Direct Capital Costs	2017-5/14/19	Remaining 2019	2020	Totals
Straight Time Labor	$55	$83	$139	$277
Overtime Labor	$0	$0	$0	$0
Outside Services	$37	$332	$1,807	$2,176
Materials	$56	$770	$559	$1,385
Other, including contingency amounts (describe)	$0	$117	$178	$295
Total Direct Costs	**$148**	**$1,302**	**$2,683**	**$4,133**
Indirect Capital Costs	**2017-5/14/19**	**Remaining 2019**	**2020**	**Totals**
Indirects/Overheads (including benefits)	$52	$436	$667	$1,155
Capitalized interest or AFUDC, if any	$1	$47	$127	$175
Total Indirect Costs	**$53**	**$483**	**$794**	**$1,330**
Total Capital Costs	**$201**	**$1,785**	**$3,477**	**$5,463**
Less Total Customer Contribution	$	$	$	$
Total Capital Project Costs	**$201**	**$1,785**	**$3,477**	**$5,463**
Total O&M Project Costs	$	$	$	$

Note: Explain unique payment provisions, if applicable:

Other/Contingency includes: Material & Equipment prices different than estimate ($75K), Severe Weather, Delays, Additional OT to meet schedule ($80K), Detail design differs from conceptual ($110K), Other – permits/fees/taxes/expenses ($30K)

Project Costs Summary (34.5kV ROW Distribution Line)

Note: Dollar values are in thousands

	Prior Authorized	Spent 2017 through 5/14/19	Remaining 2019	2020	Totals
Capital Additions - Direct	$0	$0	$57	$392	$449
Less Customer Contribution	$	$	$	$	$
Removals net of Salvage __%	$	$	$	$8	$8
Total - Direct Spending	$0	$0	$57	$400	$457
Capital Additions - Indirect	$0	$0	$98	$254	$352
Subtotal Request	$0	$0	$155	$654	$809
AFUDC	$0	$0	$4	$20	$24
Total Capital Request	$0	$0	$159	$674	$833
O&M	$	$	$	$	$
Total Request	**$0**	**$0**	**$159**	**$674**	**$833**

Financial Evaluation (34.5kV ROW Distribution Line)

Note: Dollar values are in thousands

Direct Capital Costs	2017-5/14/19	Remaining 2019	2020	Totals
Straight Time Labor	$0	$45	$12	$57
Overtime Labor	$0	$0	$0	$0
Outside Services	$0	$9	$249	$258
Materials	$0	$0	$123	$123
Other, including contingency amounts (describe)	$0	$3	$16	$19
Total Direct Costs	**$0**	**$57**	**$400**	**$457**
Indirect Capital Costs	**2017-5/14/19**	**Remaining 2019**	**2020**	**Totals**
Indirects/Overheads (including benefits)	$0	$98	$254	$352
Capitalized interest or AFUDC, if any	$0	$4	$20	$24
Total Indirect Costs	**$0**	**$102**	**$274**	**$376**
Total Capital Costs	**$0**	**$159**	**$674**	**$833**
Less Total Customer Contribution	$	$	$	$
Total Capital Project Costs	**$0**	**$159**	**$674**	**$833**
Total O&M Project Costs	$	$	$	$

Note: Explain unique payment provisions, if applicable:

Other/Contingency includes: Severe Weather, Delays, Additional OT to meet Schedule ($5K), Detail Design Differs from Conceptual ($10K), Other expenses – permits/fees ($4K)

Future Financial Impacts:

Provide below the estimated future costs that will result from the project:
Note: Dollar values are in thousands

Future Costs	Year 20__	Year 20__	Year 20__	Year 20__+	Total Future Project Costs
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Describe the estimated future Capital, O&M, and/or Other costs noted above: N/A

What functional area(s) will these future costs be funded in? N/A

A representative from the respective functional area is required to be included as a project approver.

If this is other than a Reliability Project, please complete the section below;

Provide below the estimated financial benefits that will result from the project:
Note: Dollar values are in thousands

Future Benefits	Year 20__	Year 20__	Year 20__	Year 20__+	Total Future Project Benefits
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Describe the estimated future Capital, O&M, and/or Other benefits noted above:
N/A

What functional area(s) will these benefits be reflected in: N/A

A representative from the respective functional area is required to be included as a project approver.

Asset Retirement Obligation (ARO) and/ or Environmental Cleanup Costs (Environmental Liabilities):

Is there an ARO associated with this project? If yes, please provide details: No

Are there other environmental cleanup costs associated with this project? If yes, please provide details: Yes. There is likely to be some soil remediation for the removal of the old substation and structures.

Technical Justification:

Project Need Statement

An area study was performed to address load growth and aging equipment in Rochester, NH. This was documented in the Rochester 4.16 kV Distribution System Study – January 2017. The recommendations in this report were to implement several projects to eliminate Signal Street SS, replace Twombly Street SS with a 12.47 kV 12.5 MVA substation, and convert the line voltage in the area from 4.16kV to 12.47 kV. It was preferred to eliminate/retire Signal Street SS because it is 65 years old and two sister units (Franklin and Community) have failed. Replacing the Twombly Street SS will retire a 58-year old substation and allow the conversion of the 4.16kV Rochester area to 12.47kV with additional transformation. The conversion from 4.16kV to 12.47kV increases the capacity to meet peak load, more flexibility, better reliability, allows distributed automation, and improves protection margins.

This project is for the construction of the new Twombly Street SS, removal of the existing Twombly Street SS, and rebuild of 34.5kV right of way structures to feed the new substation. The distribution 4.16kV to 12.47kV conversion project is approved and being done under project A17E09. The removal of Signal Street SS will be a separate annual work order which has not yet been established.

It was possible to build on the existing site. However, by subdividing the adjacent commercial retail properties and purchasing two small lots, the size of the substation property was increased to make construction possible without requiring a mobile and leaving the existing substation intact throughout construction.

Project Objectives

The objective of this project is to increase capacity at the Twombly Street SS to support the upgrade of the distribution system in the city of Rochester, NH to 12.47kV and increase system reliability. This project supports the upgrade of the distribution system. Additional benefits to the system that the new Twombly Street SS will enable include the following:

1. Retire a 65-year old Signal Street substation transformer.
2. Create a 12.47kV interconnected system between Portland Street and Twombly Street substations.
3. Increase switching flexibility between two (2) 12.47kV substations (Portland Street and Twombly Street).)
4. This increased switching flexibility and substation capacity will allow for the increased use of distribution automation and improve system reliability.
5. Improve the protection margins of the distribution system to improve system reliability.

Project Scope

The scope of work for this project includes the following:

- Construction of a new Twombly Street substation adjacent to the existing substation, including a transformer, circuit breakers, switches, associated foundation, control house, perimeter fencing, P&C equipment, security and animal protection system, and testing and commissioning activities;
- Removal of the existing Twombly Street substation; and
- Line work including a steel structure with three (3) phase tap, conductor, fiber optic cable installation and additional structures, as needed.

The attached drawings show the addition and removal one-line drawings and a 3D rendering of the General Arrangement. (Attachment 2 - A17E05 Twombly Removal One-line. Attachment 3 - A17E05 Twombly Addition One-line, Attachment 4 - A17E05 Twombly General Arrangement 3D).

The separate distribution 4.16kV to 12.47kV conversion project is being done under approved project A17E09. Included in the line project, the 43H1 circuit will be split and renamed 43W1 and 43W2 and fed directly from two separate breakers at the new Twombly Street SS. The removal of Signal Street SS will be a separate annual work order which has not yet been established. These projects are not included in this project scope.

The existing substation will remain energized during construction. Once the new substation is fully energized and functional, the existing substation will be removed. See Attachment 1 - A17E05 Twombly Street Scope Document - Rev D, dated 3/29/2019 for the detailed project scope of work. A summary of the major equipment to be installed and removed is provided below.

A. Major Equipment to be Installed (Electrical)

One (1) - 38kV Vacuum Circuit Breaker
Three (3) - 34.5kV Disconnect Switches (34001)
Three (3) - 34.5kV Suspension Disconnect Switches (DM02)
Two (2) - 34.5kV Disconnect Switches (DS340, 34003)
One (1) - 34.5-12.47kV. 10/12.5 MVA Transformer (TX340)
Three (3) – 30kV Station Class Lightning Arresters (Transformer)
Three (3) – 30kV Intermediate Class Lightning Arresters (340 Line)
Three (3) – 10kV Station Class Lightning Arresters (Transformer)
Six (6) – 10kV Intermediate Class Lightning Arresters (43W1, 43W2 Lines)
Three (3) – VT (Transformer)
Nine (9) - VT (43W1, 43W2 Lines, 12.47kV Bus)
Three (3) – 15kV Vacuum Circuit Breakers
Fifteen (15) – 12.47kV Disconnect Switches (43W101, 43W103, 43W201, 43W203, 392XL01)
One (1) – 12.47kV Disconnect Switches (TX34003)
Three (3) – 12.47kV Suspension Disconnect Switches (DM01)
Three (3) – Station Service Transformer
Three (3) – Fuse Cutout (Station Service Transformer)

One (1) – Station Service AC Power Panel
One (1) – AC Power Panel (Station Service)
One (1) – DC Power Panel
One (1) – Battery System
One (1) – Battery Charger
Ground Grid

B. Major Equipment to be Installed (Civil/Structural)

One (1) – 34.5kV Takeoff Structure & Foundation
Six (6) - 34.5kV Disconnect Switch Stand & Foundation (3 for 12.47kV Lines)
One (1) – 34.5kV Siemens Breaker Foundation
One (1) – 34.5kV High Bus Support & Foundation
One (1) - 34.5-12.47kV Transformer Foundation
Three (3) – 15kV Siemens Breaker Foundation
One (1) – 34.5kV Takeoff Structure & Foundation
Perimeter fence
Control House

C. Major Equipment to be Installed (P&C)

1. Cabinet #1, Transformer TX340 Primary Relaying

One (1) - Schweitzer SEL-387E Transformer Differential Relay (87/TP-TX340)
One (1) - ABB Test Switch Type FT-19R (TD1, 2, 3-87/TP-TX340)
One (1) - ABB Test Switch Type FT-19R (TD4, 5, 6-87/TP-TX340)
One (1) - Electro switch Lockout Relay (86/TP-TX340)
One (1) - Electro switch Control Switch (69/87/TP-TX340)
One (1) - ABB Test Switch Type FT-19R (TD1, 2-86/TP-TX340)
One (1) - Schweitzer SEL-351-7 Protection Relay (67H/TS-TX340)
One (1) - ABB Test Switch Type FT-19R (TD1, 2, 3-67H/TS-TX340)
One (1) - ABB Test Switch Type FT-19R (TD4, 5, 6-67H/TS-TX340)
One (1) - Electroswitch Lockout Relay (86/TS-TX340)
One (1) - Electroswitch Control Switch (69/51NL -TX340)
One (1) - ABB Test Switch Type FT-19R (TD1, 2-86/TS-TX340)
One (1) - GE HAA Target Relay (63FPX/TP-TX340)
- Various Auxiliary Relays

2. Cabinet #2, 34.5KV Breaker TB340H & TB340L Control/Relaying

One (1) - Schweitzer SEL-351-7 Overcurrent Protection Relay (50/62/BF-TB340L)
Two (2) - Electroswitch Breaker Control Switch (1-TB340H, 1-TB340L)
One (1) - Electroswitch permissive switch, (69/BF-TB340L)
Two (2) - Electroswitch Supy-Local Control Switch (43SL-TB340H, TB340L)
One (1) - Electroswitch synchronizing switch (SYN-TB340L)
One (1) - Electroswitch manual reset Lockout relay, (86/BFB1-12)
Two (2) - ABB Test Switch Type FT-19R (TD1, 2, 3-50/62/BF-TB340L), (TD4, 5, 6-50/62/BF-TB340L)
One (1) - ABB Test Switch Type FT1 (TD1-86/BFB1-12)
One (1) - Electroswitch Auto/Manual/Supervisory Switch (43AMS/LTC-TX340)
One (1) - Electroswitch Raise/Lower Switch (84RL-LTC-TX340)
One (1) - INCON LTC Position Monitor
- Various Indicating Lamps and Auxiliary Relays

3. Cabinet #3, 12.47kV Bus #1 P&C Cabinet

One (1) - Schweitzer SEL-487B Bus Differential Relay (87/B1-12)
One (1) - Electroswitch manual reset Lockout relay (86/B1-12)
One (1) - Electroswitch permissive switch, (69/B1-12)
Four (4) - Test Switch ABB type FT19R (TD1,2,3-87/B1-12), (TD4,5,6-87/B1-12), (TD7,8,9-87/B1-12), (TD1-86/B1-12)
One (1) - Dranetz type Encore 61000 (61STD) monitor, including:
- Two (2) - current/voltage modules (61MZP)
- One (1) - 5536VPOD
- One (1) - 5537APOD
- One (1) - 56K (61MDM)
- One (1) - DC power supply (61PSDC-SB)
- One (1) - Rack mount assembly (61RMTS)
  - For monitoring one bus

-Various Indicating Lamps and Auxiliary Relays

4. Cabinet #4, 12.47KV Breaker & Feeder 43W1 Control/Relaying

One (1) - Schweitzer SEL-351-7 Directional Overcurrent Relay (67/LP-43W1)
One (1) - ABB Test Switch Type FT-19R (TD1, 2, 3-67/LP-43W1)
One (1) - ABB Test Switch Type FT-19R (TD4, 5, 6-67/LP-43W1)
One (1) - Electroswitch Supervisory/Local Switch (43SL-43W1)
One (1) - Electroswitch Control Switch (1-43W1)
One (1) - Electroswitch Permissive Reclosing Control Switch (69/79-43W1)
One (1) - Electroswitch Synchronizing Switch (SYN-43W1)
One (1) - Electroswitch Setting Group Selector Switch, (43GRP-67/L-43W1)
One (1) - Electroswitch Permissive Switch (69/67/LS-43W1)
One (1) - Electroswitch Breaker Failure Permissive Switch (69/BF-43W1)
One (1) - Schweitzer SEL-451 Feeder Protection Relay (67/50BF/LS-43W1)
One (1) - ABB Test Switch Type FT-19R (TD1, 2, 3-67/50BF/LS-43W1)
One (1) - ABB Test Switch Type FT-19R (TD4, 5, 6-67/50BF/LS-43W1)
-Various Indicating Lamps and Auxiliary Relays

5. Cabinet #5, 12.47KV Breaker & Feeder 43W2 Control/Relaying

One (1) - Schweitzer SEL-351-7 Directional Overcurrent Relay (67/LP-43W2)
One (1) - ABB Test Switch Type FT-19R (TD1, 2, 3-67/LP-43W2)
One (1) - ABB Test Switch Type FT-19R (TD4, 5, 6-67/LP-43W2)
One (1) - Electroswitch Supervisory/Local Switch (43SL-43W2)
One (1) - Electroswitch Control Switch (1-43W2)
One (1) - Electroswitch Permissive Reclosing Control Switch (69/79-43W2)
One (1) - Electroswitch Synchronizing Switch (SYN-43W2)
One (1) - Electroswitch Setting Group Selector Switch, (43GRP-67/L-43W2)
One (1) - Electroswitch Permissive Switch (69/67/LS-43W2)
One (1) - Electroswitch Breaker Failure Permissive Switch (69/BF-43W2)
One (1) - Schweitzer SEL-451 Feeder Protection Relay (67/50BF/LS-43W2)
One (1) - ABB Test Switch Type FT-19R (TD1, 2, 3-67/50BF/LS-43W2)
One (1) - ABB Test Switch Type FT-19R (TD4, 5, 6-67/50BF/LS-43W2)
-Various Indicating Lamps and Auxiliary Relays

6. Cabinet #6, SCADA
   One (1) - Arbiter type GPS Clock #1093B with options 10, 92 & 93 (GPS-CLOCK)
   One (1) - GarrettCom 10XTS (SCAD)
   One (1) - Schweitzer SEL-3530 Real-Time Automation Controller (RTAC)
   One (1) - Schweitzer SEL-2242 W/ SEL-2242, SEL-2243, SEL-2244-2 (AXION CHASSIS 1)
   One (1) - Schweitzer SEL-2242 W/ SEL-2242, SEL-2243, SEL-2244-3, SEL-2245-2 (AXION CHASSIS 2)
   - Various Auxiliary Relays

7. Cabinet #7, HMI Annunciator & Communication
   One (1) - HMI Touchscreen Monitor
   One (1) - HMI Computer
   One (1) - HMI Speaker
   One (1) - HMI Speaker Switch
   One (1) - HMI DC-DC Converter
   -Various Indicating Lamps and Auxiliary Relays

8. Cabinet #8, Security & Communication
   One (1) - DC-AC Inverter
   One (1) - AC Throwover Switch
   One (1) - AC Power Strip
   One (1) - Cisco CGR2010 grid router
   One (1) - Cisco IE4010 switch
   Note that Security will not be added at this time as the Security Department recommends it for substations above 100kV. There has been no security issues with the existing substation.

9. Battery Monitor
   One (1) - Arga Battery Monitor 25-469-I420-BB
   -Various Auxiliary Relays, Switches and Fuses

10. Voltage Reduction Cabinet
    One (1) - Allen Bradley 800T Switch
    One (1) - Veeder Root Counter
    One (1) - GE EB25 Terminal Block
    -Various Aux Relays, Indicating Lamps

11. Sync Panel
    Two (2) - Yokogawa AB-16 Voltmeter, Expanded Scale 90-130V AC
    One (1) - Yokogawa AB-16 Sync Scope

12. Telco Backboard
    One (1) - Wall-Mounted 4’x8’x3/4” Plywood Backboard w/Fire Retardant Paint
    Patch Panel
    One (1) – 4” conduit to street

D. <u>Major Equipment to be Removed (Existing Twombly St. Substation)</u>
- Existing 34.5kV Disconnect Switches
- Existing Transformer 43H1
- Existing Station Service
- Existing 4.36kV Breaker
- Existing 34.5kV Disconnect Switch Stands
- Existing 34.5kV Disconnect Switch Foundations
- Existing 34.5/4.36kV Transformer Foundation
- Existing Perimeter Fence

E. <u>Major Equipment to be Installed (Line)</u>

One (1) 34.5kV Steel Structure with 3 Phase Tap
477 AAC Covered Conductor
4/0 ACSR 6/1 Neutral
ADSS Fiber Optic Cable
2,500 linear feet of Fiber Optic Installation
Four (4) 34.5kV Structure Replacements w/ Steel Poles

Background / Justification

A full background and justification for this project are in the Rochester 4kV Distribution System Study (Revision10). The downtown Rochester area is primarily served by three (3), 34.5 - 4.16 kV substations; 1) Twombly Street substation on the west side of downtown, 2) Signal Street substation in the center of downtown and 3) Portland Street on the east side of downtown. The Twombly Street and Signal Street transformers are 58 and 65 years, respectively. The Signal Street transformer has two other sister units on the Eversource system (Franklin and Community Street) that have recently failed.

The Portland Street 34.5 - 4.16kV transformer (TB341) failed and was replaced in 2010. This transformer was replaced with a dual voltage 34.5 - 4.16X12.47kV unit. This was done to allow for the future conversion of the downtown system to 12.47kV. Portland Street also has two (2) 12.47kv circuits supplied from two (2) separate 34.5 – 12.47kV transformers. The 34W4 supplies the area to the north and ties to the 39W1 circuit from the North Rochester substation. The 34W3 supplies load in the southeast of downtown Rochester. This circuit is loaded to over 97% of the transformer nameplate rating. At Portland Street SS the 4.16kV was removed and the system was converted to 12.47kV in 2018.

The project to replace the Twombly Street Substation is Phase 4 in the conversion of Rochester to 12.47kV. The original PAF outlined six phases to the Rochester area projects. These are:

Phase 1 – Convert the 34H1 from 4.16kV to 12.47kV **(Complete)**

- Install new spacer cable from Portland St. substation down Portland St. to School St. then south on Winter St.to Columbus Ave.
- Step and convert 34H1 4.16kV load as needed
- Change the transformer voltage on (TB341) at Portland S.t from 4.16kV to 12.47kV

Phase 2 – Build a new 12.47kV line from 34W3 to 43H1 **(Complete)**
- Extend 3-phase, 34W3 up Brock St. to 43H1 (0.5 mi)

Phase 3 – Convert 43H1 **(In Progress)**
- Convert 43H1 from 4.16kV to 12.47kV along Brock St. **(Complete)**
- Convert 43H1 from 4.16kV to 12.47kV along Washington St. **(Under Construction)**
- Convert 43H1 from 4.16kV to 12.47kV along Roy St. and Walnut St. to Twombly St. substation **(Construction scheduled following the Roy St. work)**
- Feed remaining 43H1 load from steps off the 340 line at North Main St. **(No longer required)**

Phase 4 – Substation Construction **(This Phase is the current project requesting Full Funding in this PAF)**
- Take Twombly St. substation out-of-service and build a new 12.47kV substation with a 34.5kV breaker and three 12.47kV breakers (1 transformer breaker and 2 line breakers)

Phase 5 – Convert 28H1 **(Future)**
- Convert the remaining 4.16kV, 28H1 circuit in Downtown Rochester

Phase 6 – Complete Conversion **(Future)**
- Continue 4.16kV conversion on 43H1, 28H1, 34H1 **(Future).** The 43H1 circuit will be split and renamed 43W1 and 43W2 and fed directly from two separate breakers at Twombly Street SS.
- Continue 4.16kV conversion on 34H2 **(Construction scheduled in 2019)**
- Retire Signal Street substation **(Future)**

Business Process and / or Technical Improvements

This project will improve the reliability of the distribution system in the city of Rochester, NH. The imminent failure of a 65-year old transformer with sister units that have already failed will be eliminated. The reliability of the underlying distribution system will be improved by converting the system to a 12.47kV voltage which will improve the protection margins and provide the ability to utilize distribution automation to effectively minimize the customer impact of unexpected outages.

Alternatives Considered with Cost Estimates

These three alternatives were considered in the Rochester 4kV Distribution System Study (Revision 10). Alternative 2 was selected. *Note: The cost estimates have not been updated from the original report.*

Alternative 1: Rebuild the 4.16kV Substations at Twombly St. and Signal St.

- Rebuild the existing 34.5 – 4.16kV substations at Twombly Street and Signal Street with 6.25 MVA transformers.
- Build a second circuit from Twombly Street substation.

The cost of this alternative was estimated at $7.950M. This alternative was not chosen because while this option would allow for switching between the 4.16kV circuits, it would leave a single 12.47kV circuit with no backup during a contingency.

Alternative 2: Build a 12.47kV Substation at Twombly St.

- Construct a new 34.5 – 12.47kV substation at Twombly Street with a 12.5 MVA transformer and two 12.47kV circuits.
- Convert the 4.16kV downtown to 12.47kV
- Retire Signal Street substation.

The cost of this alternative was estimated at $9.195M. This alternative was chosen because it creates a 12.47kV system between two substations (Twombly Street and Portland Street). This will allow for switching flexibility, for the use of distribution automation and resolve the protection coordination. This option would also provide for offloading the 34W3 circuit.

This PAF will address the construction of the new substation at Twombly Street. The conversion from 4.16kV to 12.47kV and the retirement of the Signal Street substation will be addressed under different projects.

Alternative 3: Convert Downtown to 34.5 kV

- Convert the current 4.16 kV downtown circuits to 34.5 kV.
- Create 34.5 kV ties between the new 34.5 kV circuits
- Retire the existing substations at Twombly St. and Signal St. Substations.

The cost of this alternative was estimated at $8.420M. This alternative was not chosen because it would require creating 34.5kV ties in the downtown area. This would also leave an isolated 12.47kV circuit with no ties and reduce the reliability.

Alternative 4: Construct Twombly Street SS with IEC61850 Protocol

Eversource NH is adding to their IEC61850 test facility concurrent with the construction of Twombly Street SS. It was determined that the Twombly Street substation will be a conventional control design and not IEC61850 Communication Protocol. This decision was based on the timing and smaller (34.5-12.47kV 10MVA) size of the substation.

Project Schedule

Milestone/Phase Name	Estimated Completion Date
Project Approval – Full Funding	7/1/19
Engineering/Design	10/1/2019
Procurement	1/1/2020
Construction start	1/6/2020
Testing/Commissioning	4/1/2020
In-Service Date	5/30/2020
Project Closeout	9/1/2020

Regulatory Approvals

A Building Permit from the City of Rochester, NH is required.

Risks and Risk Mitigation Plans

Coordinating with Conversion to 12.47kV

- Build a greenfield site adjacent to the existing system. Energize the new system prior to the conversion. A mobile should not be required.
- A Project Manager has been assigned to help with the coordination of the distribution line and the substation portion of the projects.

Material & Equipment pricing differs from estimate

- SS Engineering has reviewed major material prices with estimating and adjusted accordingly.
- Contingency is included in the cost estimate.

Weather delays require OT to meet the schedule

- A Project Manager has been assigned to help with coordination of the distribution line and substation portion of the projects. The schedule for cutover will be coordinated with the distribution line work which will also be affected by the weather delays.
- Contingency is included in the cost estimate.

Final design changes from the original scope of work.

- Contingency is included in the cost estimate.

References

- TAF #NH-170015DS, dated January 11, 2017
- Rochester 4kV Distribution System Study rev. 10

Attachments (One-Line Diagrams, Images, etc.)

- Attachment 1 - A17E05 Twombly Street Scope Document - Rev D
- Attachment 2 - A17E05 Twombly Removal One-line
- Attachment 3 - A17E05 Twombly Addition One-line
- Attachment 4 - A17E05 Twombly General Arrangement 3D

Project Checklist – Transmission and Substation

INSTRUCTIONS:
It is the responsibility of the initiator to contact the area disciplines to determine if the project considerations contained in this list are applicable to their project. They should fill out the checklist and determine a transition plan for the purpose of project execution.

Checklist for Studies and Processes of a Transmission & Substation Capital Project			
Project Name: Rebuild Twombly Street SS	**Project ID Number: A17E05**		
Facility Type: ☐ BPS ☐ BES ☐ PTF ☐ non-PTF ☐ CIP ☒ Distribution			
PLANNING			
Is a NX-9 required?	No		
Is an ISO-NE PAC presentation required?	No		
Is a PPA required?	No		
Is a TCA Application Required?	No		
PLANNING/PROTECTION & CONTROLS			
Are RAS/SPS/UVLs affected?	No		
OPERATIONS			
Outage Required?	☒ Primary Equipment (Power Transfer)	☐ Secondary Equipment (P&C only)	☐ Outage Not Required
Do SCLL Conditions Exist?	No		
Has an outage schedule been approved?	No		
Are Operations & Maintenance procedures/training required?	No		
STANDARDS			
Does the project include standard equipment and designs?	Yes		
SUBSTATION ENGINEERING			
Does this impact Revenue Metering	No		
Is preliminary short circuit/ breaker duty analysis required?	Yes		
Are there any changes to the baseline audible noise?	Yes		
Is there an impact to the existing ground grid?	Yes		
Is a Transient Over Voltage (TOV) analysis required?	No		
P&C ENGINEERING			
OP-22 - Are PMUs and DDR required?	No		
If BPS, is an NPCC Directory #4 presentation required?	No		

REDACTED

Checklist for Studies and Processes of a Transmission & Substation Capital Project	
Project Name: Rebuild Twombly Street SS	Project ID Number: A17E05
TRANSMISSION LINE ENGINEERING	
Are there any changes that affect the baseline EMF?	Yes
Are there any changes that affect the baseline EMI?	Yes
SITING	
Is a Siting filing required?	No
PERMITTING	
Is there any permitting required?	Yes
SITING & CONSTRUCTION SERVICES (OUTREACH)	
What is the level of outreach expected?	Medium
INITIATOR	
Has a field constructability review been completed?	Yes
INVESTMENT RECOVERY	
Does the project require development of an Investment Recovery plan?	Yes
COST ESTIMATING	
How was the cost estimate prepared?	Estimate was prepared by the Eversource Estimating Team
Who prepared the estimate?	[redacted]
Was the estimate reviewed by Eversource Estimating?	Yes - Full Review

<u>Cost Estimate Backup Details</u>