
AESC Supplemental Study

Part II: Localized Transmission and Distribution Benefits Methodology

Prepared for AESC Supplemental Study Group

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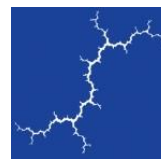
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EXECUTIVE SUMMARY

This report describes a methodology for calculating localized avoided transmission and distribution (T&D) costs from specific demand-side measures (DSM) that can be used by Massachusetts energy efficiency Program Administrators for planning purposes. As requested by the Study Group, this report does not provide actual values for avoided costs for localized T&D, nor does the proposed methodology attempt to address rate design issues. The proposed methodology is designed to utilize existing information from distribution planning groups and energy efficiency groups without the need for additional calculations or changes in current planning criteria.¹

The proposed methodology encompasses the following steps:

1. Identify target areas and required load reduction
2. Determine benefits of targeted load reductions by identified target area
3. Calculate avoided cost (\$/kW) based on the present value of deferred expenditures and the required load reduction

The above methodology for estimating localized T&D avoided costs focuses on avoided costs specific to individual Program Administrator efforts to defer or avoid specific T&D expenditures. Program Administrators will need to ensure that targeted DSM programs happen early enough and persist long enough for distribution planning groups to factor the load reduction for planning purposes. The implementation of such targeted DSM measures will need to be coordinated with each Program Administrator's distribution planning group.

The methodology described in this document can be used by program administrators to quantify the value of non-wires alternatives (NWA), but the methodology is separate from the processes or guidelines used by utilities to evaluate NWAs from a planning perspective.² Nor does this methodology attempt to address changes in electricity rates that might result from avoiding or deferring transmission or distribution projects. In addition, there are situations where utilities have found that NWAs may not be appropriate. For example, some reliability-related transmission and distribution projects will require a traditional wired solution given current distribution planning guidelines. Yet, there may be opportunities for distribution and transmission planners to consider hybrid engineering and NWA solutions.

¹ The proposed methodology does not explicitly address specific distribution and transmission project needs or cost recovery. Those issues would be raised before appropriate regulatory agencies.

² See Appendix C for a summary of current guidelines employed by the participating utilities. In addition, we note that distributed energy resources face barriers in the NWA process that are not entirely addressed in this proposed methodology.

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We also recognize that distribution utility planning will evolve with technological advancements, shifts in usage, integration of distributed energy resources (DERs), and/or changes in forecasting methodologies. As utilities implement best practices for distribution planning, those advancements should be integrated into this methodology.

The values quantified by this methodology are separate from the AESC 2018 estimated avoided pooled transmission facilities (PTF) costs of \$94/kW (2018\$).³ In addition, to avoid the double-counting of values, the location-specific avoided T&D values using this methodology would only include any Program Administrator-specific avoided T&D cost for system-wide benefits less the specific localized T&D value.

³ See AESC 2018. Section 10.3 for a detailed discussion of the derivation and calculation of the AESC 2018 avoided PTF value.



1. BACKGROUND

The 2018 AESC Study provided a general description of avoided transmission and distribution costs.⁴ AESC 2018 also identified approaches that can be used to estimate utility-wide or system-wide avoided T&D costs based on a six-step process, and it discussed some of the potential problems to be avoided (AESC 2018, see pages 195–206). In addition, AESC 2018 provided a value of avoided transmission costs associated with load reductions with respect to pooled transmission facilities (PTF) in ISO New England.⁵

For this analysis, the Massachusetts Energy Efficiency Program Administrators requested further discussion of transmission and distribution benefits, with a particular focus on benefits available from specific T&D projects through focused load reductions in constrained areas. Working on behalf of the AESC Supplemental Study Group, which consisted of Eversource, National Grid, Unitil, and Cape Light Compact, along with observers from Massachusetts state agencies including Massachusetts Department of Energy Resources (DOER), Massachusetts Energy Efficiency Advisory Council (EEAC), Massachusetts Attorney General’s Office, and Massachusetts Clean Energy Center, Synapse Energy Economics developed a methodology to quantify these benefits.

As part of this study, Synapse conducted a literature search of localized transmission and distribution projects that utilized DSM strategies and summarized these in Appendix D. In addition, Synapse polled the three participating utility sponsors for their current distribution planning and NWA guidelines (See Appendix B).

Historically, DSM planning and avoided-cost benefit assessments generally ignored localized benefits or values provided by the DSM program. Instead, these processes relied on system-wide average values.⁶ Localized benefits would be much lumpier because they would be project-specific and more time-sensitive, since localized DSM programs would need to occur before the identified construction of the traditional engineering solution to be avoided. A number of utilities and regulators have addressed targeted load-reduction programs, from Vermont in the late 1990s to Con Edison’s ongoing Brooklyn-Queens project.⁷

⁴ AESC 2018 is available at <https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf>.

⁵ AESC 2018. Chapter 10.

⁶ For a more detailed discussion of avoided T&D costs. See AESC 2018, Chapter 10.

⁷ The genesis of the Brooklyn-Queens Demand Management stemmed from a 2013 Con Edison rate case settlement followed by Con Edison’s non-wires alternative proposal in 2014.

2. OUTLINE OF PROCESS TO DETERMINE LOCALIZED T&D VALUES

To comprehensively estimate the value that distributed energy resources, namely energy efficiency and demand response, provide to localized transmission and distribution systems, program administrators can develop and rely on localized T&D values. The following sections detail our three-step process for determining localized T&D values. We also describe current practices followed by participating utilities when evaluating NWAs. We recognize that the decision process for evaluating NWAs relative to traditional engineering solutions is a different process from quantifying the avoided transmission and distribution costs for DSM planning. These three steps will require program administrators to obtain information from their respective planning groups.

2.1. Step 1: Identify Target Areas and Required Load Reduction

The localized T&D value requires the identification of target projects and required load reduction and duration in order to calculate the avoided cost. This first step of identifying target projects utilizes a utility's planning processes that identify system contingencies at peak load levels under normal and contingency operations.

Build on Existing Transmission and Distribution Planning

The first step in identifying target locations for evaluation is based on the results from utility's existing peak load forecasts at the transmission, sub-transmission, and distribution levels.⁸ The peak load forecasts should only account for program-related NWA components such as energy efficiency, PV, and demand response that are currently online and active.⁹ The peak load forecasts should be conducted in accordance with the utility's distribution and transmission planning practices and regulatory requirements (typical forecasts of five to 10 years in the future for distribution planning and 10 years for transmission and sub-transmission planning). This process may involve developing resource-specific forecasts. Stakeholders may consider evaluating peak load forecasts to include any state/local/regional electrification goals mandated by current policy, if not required by statute.

Local Transmission and Sub-transmission: After estimating peak load levels, the next step is to establish the system planning criteria and performance objectives. The system planning criteria should be based on the utility's local transmission system planning guidelines and regulatory obligations. This would involve designing the system in accordance with any relevant standards and/or design practices. For example, in New England this may include planning criteria for the bulk electric system as defined by ISO New England, North American Electric Reliability Corporation (NERC) standards, and Northeast Power Coordinating Council (NPCC). In addition, local standards may also apply (e.g., Maine's local "safe

⁸ Appendix C provides a brief summary of current planning and NWA evaluation processes for the participating utilities.

⁹ The load forecast should be the same for evaluating NWAs and traditional engineering solutions.

Harbor” reliability standards). An example of system planning criteria would involve establishing the voltage operating ranges and loading criteria for system components under normal and contingency operation—such as normal, long-term emergency and short-term emergency limit ratings for each type of equipment, i.e., the loading at which the equipment can operate in normal and emergency situations.

As part of the planning process, the planning group will run power flow simulations to identify the system contingencies and violations under varying system configurations. This may include understanding and applying the specific contingency standards (e.g., loss of element contingency such as N-0, N-1, N-1-1) that define the minimum infrastructure necessary to maintain security standards depending on the needs of the specific region. At a transmission level this is typically done through load flow analysis software such as Siemens’ PSS/E.¹⁰ The analysis should also estimate the required load reduction in order to mitigate the contingency.

Distribution System: The distribution system planning process will follow a similar process as transmission planning. Distribution planning requires projecting the peak load. This should include summer and winter peak load forecasts at a substation and circuit level. The peak load forecast should be done over a timeline that is consistent with the utility’s distribution planning process. Depending on the utility, this forecast is typically done over a 10-year period.

The next step involves setting up the design criteria for planning of the distributions system. This includes establishing criteria for equipment loading, phase balancing, and ranges of system voltages, etc. For example, at a distribution system level, Unitil establishes a 90 percent planning threshold for loads on substation transformers, stepdown transformers protective devices and other distribution circuit elements..¹¹

Following this, a circuit analysis is conducted to identify where planning criteria and design threshold violations exist and where the system constraints are expected to occur. This is typically done using distribution system planning tools, e.g., Eaton’s CYME software to assess the critical load levels, thermal, and voltage violations.¹² This step would also involve estimating the load reduction required to mitigate any identified contingencies.

Distribution system analysis should also include a process to identify potential areas where there may be reliability concerns that could be mitigated through NWA solutions.

¹⁰ For information on Siemens’ PSS/E software, see: <https://new.siemens.com/global/en/products/energy/services/transmission-distribution-smart-grid/consulting-and-planning/pss-software/pss-e.html>.

¹¹ Unitil. Distribution Planning Guide. November 19, 2019. Page 8.

¹² For information on Eaton’s CYME software, see: <http://www.cyme.com/>.

Considerations

To prioritize areas for targeted NWA, utilities currently consider various additional factors before assessing the potential for an NWA option.¹³ For example, utilities may establish minimum threshold criteria to meet when addressing a system contingency or considering an NWA as a resource option. For example, at Unitol, at the transmission and distribution level, NWA projects are reviewed for any piece of major equipment that is expected to exceed 80 percent of its seasonal normal rating during the 5-year study period and exceed 90 percent of its seasonal normal rating in year five of the study period during normal operating conditions.¹⁴ As point of comparison, National Grid in Rhode Island also states that load reduction must be less than 20 percent of the total load to be considered a defined need.¹⁵

Utilities also currently consider the timeline required for building the NWA and whether this can be done in time to avoid the identified contingency or violation that it is meant to address based on local conditions. For comparison, National Grid assumes that the start of construction of the traditional engineering solution is at least 18 months in the future in New York and 30 months in the future in Rhode Island.¹⁶ Similarly, Unitol assumes a minimum of three years to receive, evaluate, and implement NWA proposals.¹⁷ There are issues that may not be considered imminent or immediate concerns (e.g., issues that may have been accepted for many years) and should also be addressed accordingly. For example, contingencies that have sufficient lead time could be considered for NWA solutions whereas projects with imminent needs may not be suitable for NWA.

In addition, the severity and nature of the overload (e.g., the contingency number) are a consideration for the NWA process. The conditions under which the constraint or planning violation has been identified should be factored in the analysis. This might include examining the degree to which the constraint is present in normal conditions or extreme conditions (such as hot weather). Utilities also consider the nature of the contingencies in terms of whether they are suitable applications for an NWA. For example, National Grid (New York and Massachusetts) considers load relief and reliability projects as suitable for NWA solutions. National Grid (Rhode Island) specifically removes asset condition projects from consideration for NWA solutions.¹⁸ In identifying target areas where there are concerns about backing up critical loads, these areas should not be automatically disqualified from NWA

¹³ Please see Appendix B regarding concerns associated with the applicability of an NWA in estimating the localized avoided T&D costs.

¹⁴ Id. Page 8.

¹⁵ National Grid. Guidelines for Consideration of Non-Wires Alternatives in Distribution Planning. March 20, 2020.

¹⁶ It is possible that the timeline threshold may change with technological advancements and/or changes in planning cycles.

¹⁷ Unitol. Project Evaluation Procedure, Page 3, July 2018.

¹⁸ Future distribution planning guidelines may incorporate other eligible NWA situations. We see this as an area of further discussion among stakeholders.

consideration—instead hybrid solutions between the NWA and a wires solution could also be considered and evaluated by the planning group.¹⁹

DSM Planning and Implementation

On the energy efficiency side, there is need to factor in the lead time for marketing, implementation, and verification of DSM under an NWA solution. As noted in the responses provided by the utilities and stated above, current NWA evaluation processes require a window of time prior to the need to start construction on T&D infrastructure. In their DSM planning processes, program administrators should also factor the amount of DSM that could be based on potential annual load reduction (percent) by class and projected overload, as well as estimates of distributed generation and storage capacity. Conversely, a conventional engineering solution will also take time, especially if it requires Energy Facilities Siting Board (EFSB) approval and other siting review.

Identifying Expenditures Avoidable by Load Reductions

This section describes an approach to identifying expenditures that are avoidable by load reductions. It incorporates ideas from existing methodologies used by utilities to identify regions suitable for NWAs.²⁰

In identifying the expenditures avoidable by load reductions, first it is necessary to identify the magnitude, duration, and coincidence of the load reduction compared to the location and the timing of the traditional utility solution that would solve any system contingencies. Any constraints identified should be listed as such based on the first year that the constraint is identified. As discussed above, this should be identified through the system power flow analysis. At minimum, most utilities consider load growth and reliability as the expenditures that can be avoided by NWAs.²¹ However, other projects may also have some suitability in replacing a wires solution. For example, National Grid in Massachusetts identified load relief and reliability but also considers other projects to have “minimum” suitability in terms of NWA solutions. Similarly, Unitil typically considers NWAs to be suitable in addressing loading and/or voltage constraints but not suitable for condition-based replacement projects.²² If a project addresses both NWA eligible constraints and also non-NWA eligible constraints, the costs for such projects should be broken down between those that are NWA-eligible and non-NWA eligible in estimating the avoided cost expenditures. The utility should clearly identify which investments are considered as avoidable or deferrable through an NWA and the expenditures identified should be estimated in accordance with the utility capital investment planning guidelines. The expenditures should

¹⁹ As the availability and granularity of data improves through technologies and planning advancements, we anticipate improvements in methodology and applicability to more feeders.

²⁰ This methodology does not comment on the accessibility of detailed load, engineering, and cost data for feeders and components.

²¹ While overall system load growth may be flat or declining for a given utility, there still may be individual feeders that are experiencing load growth.

²² Unitil. Project Evaluation Procedure, Page 4, July 2018.

include operating expenses (e.g., reconfiguration) and capital investments and O&M associated with new facilities (net of any savings from retiring old equipment).

To estimate expenditures, Unitil and National Grid have established a traditional engineering solution cost threshold before considering NWA solutions. Small projects that can be solved through traditional utility options (low cost load transfers, etc.) may be less costly than procuring an NWA solution. Similarly, longer-term projects that do not have an imminent need and are above an established cost threshold may be more suitable projects for NWA consideration. Unitil has assessed that NWAs would generally not be evaluated if the recommended traditional option has an estimated cost of less than \$250,000.²³

Identify Type and Period of Required Reduction

After identifying the expenditures that are avoidable by targeted load reductions, it is critical to identify the time at which the required load reduction is needed. This involves answering questions such as:

- Does the load reduction need to occur in a specific season?
- Does the load reduction need to occur in specific hours of the day?
- Over how many hours or days must the load reduction occur?

In addition, it is important to identify the number of years in which the reduction must occur. For example, if the goal is to defer an expenditure for three years, and the load is expected to exceed the system's capability for all three of those years, then an effective load reduction plan requires the load reduction to sustain for three years. Program administrators will need to coordinate with the utility's distribution planning group to ensure that localized avoided distribution costs are an appropriate solution.

2.2. Step 2: Determine Benefits of Targeted Load Reductions by Identified Target Area

When calculating the avoided T&D costs, users should quantify the reduced present value of deferred expenditures. The annualized present value should reflect the utility's cost of capital, income taxes, property taxes, and insurance over the life of the equipment. To do so, one must first calculate the real carrying cost (RCC) that is expressed as a percentage. In general, the RCC equals the weighted average cost of capital (WACC), plus income tax, property tax, associated insurance, and operations and maintenance (O&M):²⁴

²³ Unitil. Project Evaluation Procedure, Page 3, July 2018.

²⁴ See AESC 2018 at page 205 for a more detailed discussion of real carrying charge. The associated insurance and O&M costs may be expressed as a percentage of the deferred expenditure being analyzed.

$$RCC = WACC + \text{Income Tax} + \text{Property Tax} + \text{Insurance} + O\&M$$

The RCC should then be used to calculate the reduced present value of the avoided expenditures. For example, if the utility's RCC is 15 percent, then a \$10 million investment would have an annualized expenditure of \$1.5 million per year (\$10 million x 15 percent).

There may be situations where a DSM load reduction defers a specific project by some period of time. For those situations and for the purposes of simplifying a more complex process, we recommend that the deferral value represents the traditional engineering expenditure reduced by the RCC and then discounted by the real discount rate.²⁵ In our illustrative example, if the RCC is 15 percent and the real discount rate is 3.37 percent, a 1-year deferral would have an avoided cost value of 85.5 percent (1 x 15 percent * (1 – 37 percent)).

2.3. Step 3: Calculate Avoided Cost (\$/kW)

The next step is to calculate the avoided cost in terms of dollar per kilowatt (\$/kW) for each identified target area.²⁶ To do so, program administrators must first compile:

1. The present value of the benefits from the deferral or avoidance of load-related expenditures identified in Step 2, above; and
2. The required load reduction, in kilowatts, required to achieve the deferral or avoidance of said expenditures.

Next, program administrators must divide the present value of the benefits from deferral or avoidance by the required load reduction to arrive at a localized avoided T&D value in dollars per kilowatt, by target area.

This value can serve as the conceptual average value for which to evaluate load reduction resources and technologies between the planning and energy efficiency groups. In other words, the average cost of the load reduction strategies used to achieve deferral or avoidance should be less than the calculated localized avoided T&D value, which is the value of the traditional engineering solution. If the average cost per kilowatt is greater than the localized avoided T&D value, then the avoidance or deferral portfolio costs more than the load-related expenditures that are targeted for deferral or avoidance. In these cases, alternative portfolios should be evaluated. If none are found to be cost-effective relative to the traditional engineering solution, the traditional engineering solution should be pursued.

²⁵ For the purposes of this methodology, we do not address any probabilistic planning issues that may arise from the continued deferral or acceleration of specific distribution project due to changes in localized loads. A more detailed analysis would require the re-running of power flow analyses based on changed loads that may result in the determination of a different engineering solution.

²⁶ This methodology does not address issues regarding operational control or visibility associated with the T&D system.

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Conceptually, it may be helpful to use the localized avoided T&D values as guidelines when compiling a portfolio to achieve the required load reduction. To the extent possible, program administrators should concentrate on achieving the required load reduction at lower costs per kilowatt than the avoided costs. However, specific resources may be less than or even greater than the average avoided cost, as long as the total portfolio cost is less than the localized avoided cost T&D value.

2.4. Illustrative Example

As a brief example, assume that the engineering solution for a load-related T&D project is estimated to cost \$10 million, and a 5 MW reduction is required to defer or avoid the project. Using the methodology described above, the localized avoided T&D value is: $\$10 \text{ million} / 5,000 \text{ kW} = \$2,000/\text{kW}$.

Expanding on this same example, the program administrator has also identified a portfolio of DERs that will cost \$1 million and achieve a load reduction of 4 MW. On a dollar per kilowatt basis, the partial, preliminary portfolio costs $\$1 \text{ million} / 4,000 \text{ kW} = \$250/\text{kW}$. This is $\$1,750/\text{kW}$ less than the localized avoided T&D value of $\$2,000/\text{kW}$, and it means that the program administrator could spend up to \$9 million on resources that achieve the remaining 1 MW of load reduction required to defer or avoid the original \$10 million in load-related expenditures. Said another way, the program administrator could procure additional resources with costs of $\$9 \text{ million} / 1,000 \text{ kW} = \$9,000 \text{ kW}$ before NWA costs exceed the engineering cost.



Appendix A. TERMINOLOGY

For this methodological analysis we define the following process terms synonymously: non-wires alternative, targeted transmission and distribution, targeted/ geotargeted DSM, locational DSM, and distributed utility planning.

Location of Resources

For resources that are behind the meter (BTM), we include customer DSM, rooftop solar, other solar that is net-metered, and some energy storage. For resources that are in front of customer meters, we include utility feeder or substation resources, community solar, microgrid solar, and other resources that are not net-metered.

Appendix B. OTHER CONSIDERATIONS

The basic premise of the proposed methodology is that an NWA (DSM or DERs) may provide an opportunity at lower costs to either: (1) defer or avoid the need of transmission and distribution equipment upgrades or (2) extend the life of existing T&D equipment. A key assumption for these two opportunities is the availability and persistence of the NWA that can be used to reduce peak demand served by the T&D equipment. There may be other additional challenges applicable to DERs that may limit their ability to participate in an NWA, these may not be addressed in this methodology.

The NWA may be just as useful for reliability if it can be implemented as soon as the traditional engineering option, even if neither quite makes the preferred timeline. Also, partial load reduction may provide adequate reliability for conditions less severe than the utility design standards (smaller contingencies and less extreme peaks). On the other hand, a traditional engineering approach is generally an “all or nothing” outcome: a partial substation or partial reconductoring of lines would not address future violations. These partial NWA situations may provide benefits to the system and could be credited with the deferral values of the traditional engineering solution.

Utilities recognize that distribution system planning is an evolving field. Electrification, DERs, DSM, technological advancements, and low to negative load growth are impacting how utilities plan and maintain the current distribution system to continue to provide safe and reliable service. Synapse recognizes that the proposed methodology incorporates what should be currently available information but does not attempt to recommend major changes in distribution planning criteria across the utilities. We hope that this methodology will foster collaboration between distribution, energy efficiency, and distributed energy resources planning efforts to minimize costs to ratepayers while maintaining reliability. We encourage stakeholders to continue discussion to improve load forecasts, NWA eligibility, cost thresholds, timeline requirements, and evaluation criteria.

Appendix C. UTILITY RESPONSES TO DISTRIBUTION PLANNING AND NWA PROCESSES

As part of this work, Synapse surveyed the participating Massachusetts utilities (Eversource, National Grid, and Unitil) about their current distribution planning and NWA processes. Synapse asked the three utilities the following questions:

1. We want to get the timing and terminology straight regarding your distribution planning process:
 - a. Does your utility have a regularly scheduled review of load and capacity for each (or most) sub-transmission line, substation, and feeder?
 - i. What is that document called?
 - ii. How often is it produced?
 - iii. How far into the future does it look? (5 years, 10 years?)
 - iv. Can we see a copy of some version of the planning document? It doesn't need to be the current version. We can view a copy on a confidential basis.
2. We know about the Brooklyn-Queens Neighborhood Program (and several other targeted load-reduction programs). Are there examples or studies you would like to bring to our attention of utilities or studies using targeted load reductions (energy efficiency, demand response, distributed energy resources) to avoid overloads or under-voltage conditions, improve reliability on a radial feeder, or otherwise avoid T&D upgrades?
3. Has your utility identified load pockets, feeders, and/or substations that may require reinforcement under current load forecasts and that might benefit from targeted load reductions?
 - a. If so, can you provide us a list of those, ideally with the load and timing issues that would require additional investment?
 - b. Is there a process to identify and/or select candidate locations for non-wire alternatives?
 - i. If so, what do you call that process?
 - ii. Is it a periodic review, or a continuing examination as potential reinforcement needs arise?
4. Has your utility identified feeders and or substations that require upgrading or other additions, but would not benefit from targeted load reductions?
 - a. If so, what sorts of projects fall into that category?
 - b. Is there a process to identify planned investments that will not be affected by load level?

The following provides a brief summary of their responses.

Eversource indicated that current distribution planning occurs once a year that analyzes load and capacity for all substations and most feeders. This planning assessment looks ahead 5–10 years. At the distribution level, Eversource indicated that its annual review process identifies the substations/area

that may require reinforcement under current load forecast and that might benefit from targeted load reduction. At this time Eversource indicated that it has not compiled a list of feeders or substation projects that may benefit from targeted load reductions. At the transmission level, Eversource indicated that for projects that require the Energy and Infrastructure Siting Board (EISB) approval, the company evaluates NWAs.

National Grid indicated that current distribution planning occurs once a year. This planning assessment looks at loads for 15 years and is summarized in National Grid’s Annual Reliability Report.²⁷ We understand that the unredacted version identifies distribution assets nearing or exceeding the company’s ratings in the next five years. National Grid has a published company’s process flow for considering NWAs.²⁸ In a separate document, National Grid describes its guidelines for NWAs that outlines the company’s project criteria, timeline for consideration, and cost threshold.²⁹ A summary of those criteria by state are shown in Table 1.

Table 1. Summary of National Grid’s NWA guidelines

Criteria	New York & Massachusetts	Rhode Island
Project Applicability	Project types include Load Relief and Reliability. Other types have minimal suitability and will be reviewed as suitability changes due to State policy or technological changes.	Project types include Load Relief and Reliability. The need is not based on Asset Condition. If load reduction is necessary, then it will be less than 20% of the total load in the area of the defined need.
Timeline for NWA Consideration	Start of construction is at least 18 months in the future	Start of construction is at least 30 months in the future
Cost Threshold for NWA Consideration	Greater than or equal to \$500K	Greater than \$1M

For projects that can consider an NWA, the company posts RFPs for NWA opportunities.³⁰ National Grid evaluates NWA RFP responses and then subjects the NWA to the applicable approval process before proceeding with contract negotiations with the NWA vendor.

Unitil’s current distribution planning occurs once a year and encompasses a 5-year planning horizon.³¹ For NWA considerations, the company identifies equipment that reaches 80 percent of the equipment’s seasonal rating during the 5-year study period. The company indicated that the 80 percent threshold

²⁷ See http://ngrid-ftp.s3.amazonaws.com/MASysDataPortal/MA-DPU_ARR2018_2018-04-17_REDACTED.pdf.

²⁸ See <https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/Planning-Process>.

²⁹ National Grid. Guidelines for Consideration of Non-Wires Alternatives in Distribution Planning. March 20, 2020.

³⁰ See <https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/Opportunities>.

³¹ Unitil Distribution Planning Guide. November 19, 2019. Section 4.1.



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accounts for lead times needed to implement NWA solutions.³² By comparison, the company's traditional engineering solutions are evaluated when equipment reaches 90 percent of its seasonal rating.³³ For planning purposes, Unitil currently utilizes a traditional engineering solution threshold value of \$250,000 before considering an NWA solution.³⁴ Second, Unitil requires that the traditional engineering solution lead time to be three to five years as part of the NWA evaluation process.³⁵ Third, Unitil factors in whether or not the traditional engineering solution is required to address loading or voltage criteria violations.³⁶ Projects that address aging equipment may still be evaluated for NWAs, but may not result in the issuance of an NWA RFP. Should a traditional engineering project meet the three criteria, Unitil will then issue an RFP for NWA solutions. Proposed NWAs are then reviewed through an evaluation process to score relative options for the company.

³² Id. Section 4.3.

³³ Ibid.

³⁴ Unitil Project Evaluation Guideline. July 9, 2018. Section 3.1.4.

³⁵ Id. Section 3.1.5

³⁶ Id. Section 3.1.6



Appendix D. LITERATURE REVIEW OF TARGETED LOAD-REDUCTION PROJECTS ACROSS THE UNITED STATES AND CANADA

This literature review provides a summary of cases studies, articles, and reports that identify targeted load-reduction projects across the United States and Canada. The goal of this literature review was to determine if there is a pattern across projects that would be applicable for Massachusetts electric program administrators, with an aim to translate this pattern into a methodology that could be used to estimate the localized avoided costs of avoiding transmission and distribution with distributed energy resources. This document is accompanied by an Excel workbook that contains technical details of our review.

To the extent possible, our literature review focused on collecting information on the timing of construction needs and of critical decision points, the cost of the deferrable equipment, and the value of annual deferral and the value and probability of indefinite avoidance—if load growth does not materialize or if the load reductions offset growth until load stabilizes. We have also documented, where possible, how projects have dealt with the following:

- Deferral of multiple components (e.g., a new feeder, a new substation transformer, and a new transmission line to the transformer);
- Identification of the geographical area in which load reductions would be helpful (e.g., by reducing load on neighboring substations, allowing transfer of load from the constrained substation); and
- The applicability of specific resources (e.g., PV, cogeneration, and special rates).

D.1. Specific Case Studies

We summarize the identified projects and articles below:

XCEL Rooney Valley geo-targeting (Colorado) (vertically integrated utility)

Xcel's 2019/2020 DSM plan proposes a pilot project to obtain 3 MW of load reduction in the Rooney Valley that is experiencing rapid load growth from new development.³⁷ The goal of this pilot project is to defer the need to add a new feeder and transformer to the existing substation serving the area. Xcel estimates that a substation upgrade is needed by 2023 and has an estimated cost of \$10.1 million. Xcel claims that 1 MW of load reduction is currently available and has designed a program targeting new

³⁷ Available at: <https://www.xcelenergy.com/staticfiles/xcel-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/DSM-Plan.pdf>.

construction through EnergyStar HVAC equipment and smart thermostats. Xcel claims that the 3 MW load reduction would need to occur approximately 44 hours per year by 2026 to defer the substation upgrades. This pilot is ongoing.

PGE targeted DSM in Portland (Oregon) (vertically integrated utility)

- 1993 pilot project (Two pilots, one targeting suburban spot network and one targeting downtown grid network substations)³⁸
- Spot network pilot program targeted four areas
- Spot network focused on increased contract with customers from utility's existing programs
 - Results indicated that one of the four projects delayed T&D upgrades
 - New load growth in one building overrode targeted savings
- Grid network pilot program targeted three downtown areas
- For Grid Network: ESCO employed with tiered incentive structure in attempt to achieve greater than 20 percent energy savings
- One of the three areas had results at time of study
- Construction proceeding before pilot program ended

Geo-targeted DSM (Massachusetts) (transmission and distribution utility)

A 2015 Dunsky report details a benefit-cost methodology focused on local T&D avoided costs.³⁹ The report outlines a five-step calculation for local T&D avoided costs:

1. Assess Local Peak Forecast in the absence of forecasted DSM
2. Assess Poles and Wires Investment schedule
3. Adjust the Avoided T&D costs calculator
4. Analysis without/with DSM
5. Application in cost-effectiveness

The report notes that the system average avoided T&D costs would need to be re-adjusted so as to avoid double-counting of localized avoided T&D benefits.

³⁸ See https://www.aceee.org/files/proceedings/1994/data/papers/SS94_Panel2_Paper30.pdf.

³⁹ *Energy Efficiency as a Transmission and Distribution Resource Using Geotargeting*. NEEP (2015). Available at <https://neep.org/energy-efficiency-transmission-and-distribution-resource-using-geotargeting>.

Non-Wires Alternative: Case studies from leading U.S. projects (various locations)

This 2018 report summarize 10 projects across the country.⁴⁰ While not all of the projects were complete, the authors found that NWA solutions were able to cost-effectively extend the lives of existing assets. The authors noted that NWAs could be phased in stages with load growth.

Locational system relief value (New York)

The New York State Public Service Commission has established a Value of Distributed Energy Resources (VDER) tariff.⁴¹ The tariff includes a Value Stack payment methodology, based on stacking the benefits of DERs. Included in the Value Stack is the locational system relief value (LSRV), along with energy, capacity, environmental, and demand reduction values (DRVs). The LSRV is calculated by “deaveraging” the utility’s marginal cost of service (MCOS) studies, and the values represent long-run avoided costs of incremental distribution system upgrades. Specifically, this deaveraging process takes the following steps:

1. First, a “draft” DRV is calculated by estimating the cost of transmission upgrades (in dollars) and dividing that quantity by the expected increase in load (in kW) that transmission upgrade is expected to serve for the entire system.
2. Second, individual, location-specific transmission upgrades are separately assessed. Similar to Step 1, each of these upgrades is evaluated based on estimated cost, and expected ability to increase load. Costs are divided by load increases to derive LSRVs.
3. Third, each LSRV is compared to the systemwide draft DRV. If an LSRV is greater than the draft DRV, it is identified as being eligible for a higher LSRV avoided cost.
4. Fourth, costs and load increases for each eligible LSRV are subtracted from the draft DRV. The draft DRV is then re-calculated as a final DRV, absent the cost and kW impacts of all the individual eligible LSRVs.

The costs are intended to compensate DERs for the value they provide in deferring or avoiding distribution system upgrades. DERs located in areas with eligible LSRVs are assigned the higher, respective LSRV avoided cost. DERs located in all other areas are assigned the systemwide final DRV as an avoided cost. DRVs and LSRVs are recalculated every year, but resources receiving a DRV value receive that value for 10 years. Resources receiving a higher LSRV value are guaranteed to receive it for one year only.

⁴⁰ See https://e4thefuture.org/wp-content/uploads/2018/11/2018-Non-Wires-Alternatives-Report_FINAL.pdf.

⁴¹ See <https://www.nyseda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources>. See also <http://www.synapse-energy.com/sites/default/files/ACEEE-Paper-Values-EE-DER.pdf>.

Locational net benefits methodology (California)

In 2015, the California Public Utilities Commission (CPUC) issued a guidance document that instructed the three California investor-owned utilities to develop a locational net benefits methodology (LNBM).⁴² The methodology is used to develop locational net benefit values of DERs; however, it is not used to develop compensation amounts to be paid to DERs. The LNBM value components include: avoided sub-transmission, substation and feeder capital and operating expenditures, avoided distribution voltage and power quality capital and operating expenditures, avoided distribution reliability and resiliency capital and operating expenditures, and avoided transmission capital and operating expenditures.

The values are developed on an hourly basis and over a 30-year time horizon. This temporal granularity is intended to provide very clear value signals about the needs of a region, and to help resource planners and potential project developers identify appropriate technologies or portfolios of technologies to meet regional needs.

Locational demand-side management pilot (Nova Scotia)

In 2018, EfficiencyOne and Nova Scotia Power submitted a *2018 Locational DSM Update* in which they identified the area served by a substation as possibly well-suited to implement and pilot a locational demand-side management program.⁴³ The region was selected as a suitable site for the pilot because there may be a large load addition driven by a possible large customer that would require the rebuilding of a transmission line and the replacement of the substation transformers. EfficiencyOne and Nova Scotia Power have submitted their plans to the DSM Advisory Group and continue to seek feedback on their proposed pilot prior to its implementation. In its current form, the pilot is expected to implement a portfolio of peak reduction measures. EfficiencyOne and Nova Scotia Power will then track the demand energy reduction impacts, measure lives, and customer and utility costs of the pilot.

Mt. Vernon substation non-wires alternatives (Washington, D.C.)

Synapse was retained by the District of Columbia Department of Energy and Environment to explore alternatives to building a new Mt. Vernon substation in Washington, D.C.⁴⁴ Pepco Holdings Inc. proposed to build the new substation with an online date of June 1, 2022. The proposed substation would cost more than \$150 million. Synapse analyzed the economics of substation deferral and found that each year of deferral would save ratepayers more than \$8 million. The deferral could be achieved using a portfolio of DERs such as energy efficiency, distributed generation, demand response, and

⁴² See <https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5108>. See also <http://www.synapse-energy.com/sites/default/files/ACEEE-Paper-Values-EE-DER.pdf>.

⁴³ Details available in Docket M07815, available at <https://uarb.novascotia.ca/fmi/webd/UARB15>. See: <https://www.synapse-energy.com/sites/default/files/Synapse-comments-on-Locational-DSM-Pilot-Update.pdf>.

⁴⁴ See: <https://edocket.dcpsc.org/apis/api/filing/download?attachId=77396&guidFileName=32c43daa-5658-4623-89fd-cc0df091b882.pdf>.

battery storage. Despite these findings, the Public Service Commission of the District of Columbia recently approved construction of the substation.⁴⁵

Brooklyn Queens Demand Management Program (New York)

In 2015, Con Ed faced \$1.2 billion in investments to avoid overloads by 2018 on the sub-transmission system serving a large section of Queens and a small part of Brooklyn. Con Ed proposed a mix of peak-targeted commercial and residential energy-efficiency investment, behind-the-meter and utility-side storage, voltage optimization, distributed generation, and other measures. The program has met its initial 52 MW target for peak reduction, pushing the T&D investments to 2026, and has been extended to continue deferring the investments.⁴⁶

Vermont non-transmission alternative screening (Vermont)

Vermont has developed a screening process and tool to identify opportunities to incorporate a combination of energy efficiency, demand response, generation, and transmission to address identified reliability issues within the state. The Vermont System Planning Committee (VSPC) requires the completion of a screening form for all proposed upgrades.⁴⁷ In addition, the VSPC has developed a screening tool to evaluate non-transmission alternatives.⁴⁸

D.2. Academic Studies

Academic studies on this subject include:

Distribution Feeder Upgrade Deferral through the Use of Energy Storage Systems (2016)

This academic paper examined energy storage options as a means to defer feeder upgrades.⁴⁹ The paper found that for battery storage, the cost of the battery storage, the cost of the feeder upgrade, and load growth are key factors to determine the cost-effectiveness of energy storage as a means for feeder upgrade deferral.

⁴⁵ See: <https://www.globenewswire.com/news-release/2019/12/20/1963549/0/en/DC-Utility-Regulator-Approves-Pepco-Capital-Grid-Project.html>.

⁴⁶ See <https://insideclimatenews.org/news/04042016/coned-brooklyn-queens-energy-demand-management-project-solar-fuel-cells-climate-change> and <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=45800>.

⁴⁷ See https://www.velco.com/uploads/vspc/documents/ntascreeningtool_2012_09_27.pdf.

⁴⁸ See https://www.velco.com/uploads/vspc/documents/ntascreening_6290.pdf.

⁴⁹ See https://www.researchgate.net/publication/318295134_Distribution_feeder_upgrade_deferral_through_use_of_energy_storage_systems.

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Overview of Integrated Distribution Planning Concepts and State Activity (2018)

This presentation provides some examples of NWA activities underway in New York, Oregon, California, and Rhode Island.⁵⁰ One example noted in the presentation is the RI System Data Portal to identify opportunities for NWAs.

⁵⁰ Available at <https://emp.lbl.gov/publications/overview-integrated-distribution>. See slides 23-31.



Appendix E. LITERATURE REVIEW TABLES

The following table shows the studies we identified and our categorization of each study.

Juris-diction	Project/Program	Proponent/Lead	Date range (from)	Date range (to)	Issue	Equipment Level	Resources Considered	Resources Utilized	Status/Outcome	Source
NS	feeder 82V-401	NSPower	March 2017	present	wind integration, radial feeder backup for loss of supply			Storage		51
AZ	Punkin Center	APS	2017	present	overload of 20 mi of 21kV feeder	T&D lines		Storage		52
CA	Browns Valley	PG&E			Overloads	D S/S		Storage		53
CO	Rooney Valley Geo-Targeting	Excel	2019	2020	Anticipated thermal overloading of Kendrick substation due to load growth. Estimated upgrade cost of \$10.1 million	Substation	DSM (EE and DR) for new construction	EE	Pilot Stage	54
OR	Targeted EE programs in Portland	PGE	1993		Deferral of planned distribution upgrades	Substation	EE and ESCO	ESCO	Completed, muted success	55

⁵¹ <https://uarb.novascotia.ca/fmi/webd/UARB15>.

⁵² <https://www.utilitydive.com/news/storage-for-td-deferral-works-arizona-public-service-finds-in-tonto-natio/511485/>.

⁵³ <https://www.tdworld.com/electric-utility-operations/article/20969896/california-utility-constructs-peakshaving-storage-facility>.

⁵⁴ <https://www.xcelenergy.com/staticfiles/xcel-responsive/Company/Rates%20%20Regulations/Regulatory%20Filings/DSM-Plan.pdf>.

⁵⁵ https://www.aceee.org/files/proceedings/1994/data/papers/SS94_Panel2_Paper30.pdf.

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Juris- diction	Project/ Program	Proponent/ Lead	Date range (from)	Date range (to)	Issue	Equipment Level	Resources Considered	Resources Utilized	Status/ Outcome	Source
CA	EPIC 2.22 Demand Reduction through Targeted Data Analysis	PG&E	2019		Targeted DSM Program		Multiple solutions for planning		Pilot Stage	56
NY	Locational System Relief Value	NY PSC	2017	present	Compensate DERs for their locational benefits	Substation	Solar, wind, hydroelectric, farm-based anaerobic digesters, fuel cells (<= 2 MW)	Solar, wind, hydroelectric, farm-based anaerobic digesters, fuel cells, standalone storage (<= 5 MW)	Implemented	57
CA	Locational Net Benefits Methodology	CPUC	2015	present	Develop locational net benefit values of DERs	T&D capital and OpEx	DERs (distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies)	Unchanged	Implemented	58
NS	Locational DSM Pilot	Efficiency One	2018	present	Implementation of a locational DSM pilot to avoid a potential substation upgrade	Substation	DSM measures		Proposed pilot	59

⁵⁶ https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.22.pdf.

⁵⁷ <https://www.nyscrda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources>.

⁵⁸ <https://drpwwg.org/sample-page/drp/>.

⁵⁹ <https://www.synapse-energy.com/sites/default/files/Synapse-comments-on-Locational-DSM-Pilot-Update.pdf>.

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Juris-diction	Project/Program	Proponent/Lead	Date range (from)	Date range (to)	Issue	Equipment Level	Resources Considered	Resources Utilized	Status/Outcome	Source
DC	Mt. Vernon Substation NWA	DC DOEE	2017	2019	Deferring or avoiding a proposed substation (Mt. Vernon)	Substation	Energy efficiency, distributed generation, demand response, battery storage		Not implemented	60
VT	Non-transmission screening process	VSPC			Process and tool to screen non-transmission alternatives	Sub-transmission	Energy efficiency, distributed generation, demand response		In place	61
NY	Brooklyn-Queens Program	Con Ed	2015	present	Potential Overload	Sub-transmission system: expanding 345 kV S/S, new sub-transmission feeder to new D S/S	Energy efficiency, distributed generation, demand response, CHP, fuel cell, voltage optimization, battery storage	Energy efficiency, distributed generation, demand response, CHP, fuel cell, voltage optimization, battery storage	Reductions achieved; extended	62

⁶⁰ <http://www.synapse-energy.com/sites/default/files/Mt-Vernon-Substation-17-105-17-047.pdf> .

⁶¹ <https://www.vermontspc.com/about/key-documents>.

⁶² <https://www.utilitydive.com/news/bqdm-program-demonstrates-benefits-of-non-traditional-utility-investments/550110/>; <https://info.aee.net/navigating-utility-business-model-reform-case-studies>; and <https://info.aee.net/navigating-utility-business-model-reform-case-studies>.