# CHRISTOPHER NEME, PRINCIPAL

## EDUCATION

M.P.P., University of Michigan, 1986
B.A.., Political Science, University of Michigan, 1985

## EXPERIENCE

2010-present: Principal (and Co-Founder), Energy Futures Group, Hinesburg, VT
1999-2010: Director of Planning & Evaluation, Vermont Energy Investment Corp., Burlington, VT
1993-1999: Senior Analyst, Vermont Energy Investment Corp., Burlington, VT
1992-1993: Energy Consultant, Lawrence Berkeley National Laboratory, Gaborone, Botswana
1986-1991: Senior Policy Analyst, Center for Clean Air Policy, Washington, DC

## PROFESSIONAL SUMMARY

Chris specializes in analysis of markets for energy efficiency, demand response, renewable energy and strategic electrification measures and the design and evaluation of programs and policies to promote them. During his 25+ years in the clean energy industry, Mr. Neme has worked for energy regulators, utilities, government agencies and advocacy organizations in nearly 30 states, 5 Canadian provinces and several European countries. He has defended expert witness testimony before regulatory commissions in eleven different jurisdictions; he has also testified before several state legislatures. Chris has also authored or co-authored numerous reports and papers regarding energy efficiency policies and programs, including the first edition (Spring 2017) of the *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources* and several reports on non-wires alternatives.

## SELECTED PROJECTS

- ***Natural Resources Defense Council (Illinois, Michigan and Ohio).*** Critically review multi-year efficiency, demand response, distribution system investment and integrated resource plans filed by Illinois, Michigan and Ohio utilities. Draft and defend regulatory testimony on critiques. Represent NRDC in regular stakeholder-utility processes governing development of efficiency policy manuals, annual TRM updates, annual NTG updates, and other planning and evaluation issues. Also represent NRDC in collaborative development of non-wires alternative pilots. Supported development of Illinois clean energy bill adopted in late 2016. (2010 to present)
- ***Ontario Energy Board:*** Serve on provincial gas DSM Evaluation Advisory Committee. Work includes input on multi-year evaluation plans, input on scopes of work for evaluation studies, serving on OEB teams that review and score proposals submitted in response to evaluation RFPs, and critical review and input on independent evaluator assessments of utilities' annual gas savings claims. Also serve on advisory committees on gas and electric efficiency potential studies and advisory committee on carbon price forecast studies. (2015-present)
- ***E4TheFuture.*** Co-authored first edition (Spring 2017) of the National Standard Practice Manual (NSPM) for cost-effectiveness analysis of energy efficiency and other distributed resource measures. Presenting the NSPM to a wide variety of audiences across the U.S. and Canada. Also helping regulators and other parties in several jurisdictions to assess opportunities to better align local cost-effectiveness screening practices with the NSPM. (2016 to present)

- ***Green Mountain Power (Vermont).*** Support development and implementation of GMP's compliance plan for Vermont RPS Tier 3 requirement to reduce customers' direct consumption of fossil fuels, with significant emphasis on strategic electrification strategies. Also developed 10-year forecast of sales that could result from three different levels of policy/program promotion of residential electric space heating, electric water heating and electric vehicles. (2016 to present)
- ***New Jersey Board of Public Utilities.*** Serve on management team responsible for statewide delivery of New Jersey Clean Energy Programs. Lead strategic planning; support regulatory filings, cost-effectiveness analysis & evaluation work. (2015 to present) Served on management team for start-up of residential and renewables programs for predecessor project. (2006-2010)
- ***Regulatory Assistance Project - U.S.*** Provide guidance on efficiency policy and programs. Lead author on strategic reports on achieving 30% electricity savings in 10 years, using efficiency to defer T&D system investments, & bidding efficiency into capacity markets. (2010 to present)
- ***Regulatory Assistance Project - Europe.*** Provide on-going support on efficiency policies and programs in the United Kingdom, Germany, and other countries. Reviewed draft European Union policies on Energy Savings Obligations, EM&V protocols, and related issues. Drafted policy brief on efficiency feed-in-tariffs and roadmap for residential retrofits. (2009 to present)
- ***Alberta Energy Efficiency Alliance.*** Drafted white paper how treatment of "efficiency as a resource" could be institutionalized in Alberta. The paper followed several presentations to government agencies and others on behalf of the Pembina Institute. (2017 to 2018)
- ***Green Energy Coalition (Ontario).*** Represent coalition of environmental groups in regulatory proceedings, utility negotiations and stakeholder meetings on DSM policies (including integrated resource planning on pipeline expansions) and utility proposed DSM Plans. (1993 to present)
- ***Southern Environmental Law Center.*** Assessed reasonableness of Duke Energy's historic efficiency program savings claims, as well as the design of their efficiency program portfolios for 2019. Filed expert witness testimony on findings in North Carolina dockets (2018).
- **Toronto Atmospheric Fund.** Helped draft an assessment of efficiency potential from retrofitting of cold climate heat pumps into electrically heated multi-family buildings (2017).
- ***Northeast Energy Efficiency Partnerships.*** Helped manage Regional EM&V forum project estimating savings for emerging technologies, including field study of cold climate heat pumps. Led assessment of best practices on use of efficiency to defer T&D investment. (2009 to 2015)
- ***Ontario Power Authority.*** Managed jurisdictional scans on leveraging building efficiency labeling/disclosure requirements and non-energy benefits in cost-effectiveness screening. Supported staff workshop on the role efficiency can play in deferring T&D investments. Presented on efficiency trends for Advisory Council on Energy Efficiency. (2012-2015)
- ***Vermont Public Interest Research Group***. Conducted comparative analysis of the economic and environmental impacts of fuel-switching from oil/propane heating to either natural gas or efficient, cold climate electric heat pumps. Filed regulatory testimony on findings. (2014-2015)

- ***New Hampshire Electric Co-op.*** Led assessment of the co-op's environmental and social responsibility programs' promotion of whole building efficiency retrofits, cold climate heat pumps and renewable energy systems. Presented recommendations to the co-op Board. (2014)
- ***National Association of Regulatory Utility Commissioners (NARUC).*** Assessed alternatives to first year savings goals to eliminate disincentives to invest in longer-lived measures and programs. (2013)
- ***California Investor-Owned Utility***. Senior advisor on EFG project to compare the cost of saved energy across ~10 leading U.S. utility portfolios. The research sought to determine if there are discernable differences in the cost of saved energy related to utility spending in specific non-incentive categories, including administration, marketing, and EM&V. (2013)
- ***DC Department of the Environment (Washington DC).*** Part of VEIC team administering the DC Sustainable Energy Utility (SEU). Helped characterize the DC efficiency market and supporting the design of efficiency programs that the SEU will be implementing. (2011 to 2012)
- ***Ohio Sierra Club.*** Filed and defended expert witness testimony on the implications of not fully bidding all efficiency resources into the PJM capacity market. (2012)
- ***Regulatory Assistance Project – Global.*** Assisted RAP in framing several global research reports. Co-authored the first report – an extensive "best practices guide" on government policies for achieving energy efficiency objectives, drawing on experience with a variety of policy mechanism employed around the world. (2011)
- ***Tennessee Valley Authority.*** Assisted CSG team providing input to TVA on the redesign of its residential efficiency program portfolio to meet aggressive new five-year savings goals. (2010)
- ***New York State Energy Research and Development Authority (NYSERDA).*** Led residential & renewables portions of several statewide efficiency potential studies. (2001 to 2010)
- ***Ohio Public Utilities Commission.*** Senior Advisor to a project to develop a web-based Technical Reference Manual (TRM). The TRM includes deemed savings assumptions, deemed calculated savings algorithms and custom savings protocols. It was designed to serve as the basis for all electric and gas efficiency program savings claims in the state. (2009 to 2010)
- ***Vermont Electric Power Company.*** Led residential portion of efficiency potential study to assess alternatives to new transmission line. Testified before Public Service Board. (2001-2003)
- ***Efficiency Vermont.*** Served on Sr. Management team. Supported initial project start-up. Oversaw residential planning, input to regulators on evaluation, input to regional EM&V forum, development of M&V plan and other aspects of bidding efficiency into New England's Forward Capacity Market (FCM), and development and updating of nation's first TRM. (2000 to 2010)
- ***Long Island Power Authority Clean Energy Plan***. Led team that designed the four major residential programs (three efficiency, one PV) incorporated into the plan in 1999. Oversaw extensive technical support to the implementation of those programs. This involved assistance with the development of goals and budgets, development of savings algorithms, cost-effectiveness screening, and on-going program design refinements. (1998 to 2009)

## SELECTED PUBLICATIONS AND REPORTS

- *Recommendations for Accelerating Adoption of Heat Pumps in the Ontario eMURB Sector*, Toronto Atmospheric Fund, forthcoming in 2018 (with Devon Calder, Brian Purcell and Judy Simon)
- *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*, Edition 1, Spring 2017 (with Tim Woolf, Marty Kushler, Steven Schiller and Tom Eckman)
- *The Next Quantum Leap in Efficiency: 30% Electricity Savings in 10 Years*, Proceedings of the 2016 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 9, pp. 1-14 (with Jim Grevatt, Rich Sedano and Dave Farnsworth)
- *The Next Quantum Leap in Efficiency: 30% Electricity Savings in Ten Years*, published by the Regulatory Assistance Project, February 2016 (with Jim Grevatt)
- *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments*, published by Northeast Energy Efficiency Partnerships, January 9, 2015 (with Jim Grevatt)
- *Unleashing Energy Efficiency: The Best Way to Comply with EPA's Clean Power Plan*, Public Utilities Fortnightly, October 2014, pp. 30-38 (with Tim Woolf, Erin Malone and Robin LeBaron)
- *The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening*, published by the National Efficiency Screening Project, August 2014 (with Tim Woolf et al.)
- *U.S. Experience with Participation of Energy Efficiency in Electric Capacity Markets*, Regulatory Assistance Project, August 2014 (with Richard Cowart)
- *The Positive Effects of Energy Efficiency on the German Electricity Sector*, IEPEC 2014 Conference, September 2014 (with Friedrich Seefeldt et al.)
- *Final Report: Alternative Michigan Energy Savings Goals to Promote Longer Term Savings and Address Small Utility Challenges*, prepared for the Michigan Public Service Commission, September 13, 2013 (with Optimal Energy)
- *Energy Efficiency Feed-in-Tariffs: Key Policy and Design Considerations*, Proceedings of ECEEE 2013 Summer Study, pp 305-315 (with Richard Cowart)
- *Can Competition Accelerate Energy Savings? Options and Challenges for Efficiency Feed-in-Tariffs*, published in Energy & Environment, Volume 24, No. 1-2, February 2013 (with Richard Cowart)
- *An Energy Efficiency Feed-in-Tariff: Key Policy and Design Considerations*, published by the Regulatory Assistance Project, March/April 2012 (with Richard Cowart)
- *U.S. Experience with Efficiency as a Transmission and Distribution System Resource*, published by the Regulatory Assistance Project, February 2012 (with Rich Sedano)
- *Achieving Energy Efficiency: A Global Best Practices Guide on Government Policies*, published by the Regulatory Assistance Project, February 2012 (with Nancy Wasserman)

- *Residential Efficiency Retrofits: A Roadmap for the Future*, published by the Regulatory Assistance Project, May 2011 (with Meg Gottstein and Blair Hamilton)
- *Is it Time to Ditch the TRC?* Proceedings of ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5 (with Marty Kushler)
- *Energy Efficiency as a Resource in the ISO New England Forward Capacity Market*, in Energy Efficiency, published on line 06 June 2010 (with Cheryl Jenkins and Shawn Enterline)
- *A Comparison of Energy Efficiency Programmes for Existing Homes in Eleven Countries*, prepared for the British Department of Energy and Climate Change, 19 February, 2010 (with Blair Hamilton et al.)
- *Energy Efficiency as a Resource in the ISO New England Forward Capacity Market*, Proceedings of the 2009 European Council on an Energy Efficient Economy Summer Study, pp. 175-183 (with Cheryl Jenkins and Shawn Enterline)
- *Playing with the Big Boys: Energy Efficiency as a Resource in the ISO New England Forward Capacity Market*, Proceedings of ACEEE 2008 Summer Study Conference on Energy Efficiency in Buildings, Volume 5 (with Cheryl Jenkins and Blair Hamilton)
- *Recommendations for Community-Based Energy Program Strategies, Final Report*, developed for the Energy Trust of Oregon, June 1, 2005 (with Dave Hewitt et al.)
- *Shareholder Incentives for Gas DSM: Experience with One Canadian Utility*, Proceedings of ACEEE 2004 Summer Study on Energy Efficiency in Buildings, Volume 5 (with Kai Millyard)
- *Cost Effective Contributions to New York's Greenhouse Gas Emission Reduction Targets from Enegy Efficiency and Renewable Energy Resources*, ACEEE 2004 Summer Study Proceedings, Volume 8 (with David Hill et al.)
- *Opportunities for Accelerated Electric Energy Efficiency Potential in Quebec: 2005-2012*, prepared for Regroupement national des conseils regionaux de l'environnement du Quebec, Regroupement des organisms environnementaux energie and Regroupement pour la responsabilite sociale des enterprises, May 16, 2004 (with Eric Belliveau, John Plunkett and Phil Dunsky)
- *Review of Connecticut's Conservation and Load Management Administrator Performance, Plans and Incentives*, for Connecticut Office of Consumer Counsel, October 31, 2003 (with John Plunkett, Phil Mosenthal, Stuart Slote, Francis Wyatt, Bill Kallock and Paul Horowitz)
- *Energy Efficiency and Renewable Energy Resource Development Potential in New York State*, for New York Energy Research and Development Authority, August 2003 (with John Plunkett, Phil Mosenthal, Stave Nadel, Neal Elliott, David Hill and Christine Donovan)
- *Assessment of Economically Deliverable Transmission Capacity from Targeted Energy Efficiency Investments in the Inner and Metro-Area and Northwest and Northwest/Central Load Zones", for Vermont Electric Power Company, Final Report: April 2003* (with John Plunkett et al.)
- *Residential HVAC Quality Installation: New Partnership Opportunities and Approaches*, Proceedings of ACEEE 2002 Summer Study Conference on Energy Efficiency in Buildings, Volume 6 (with Rebecca Foster, Mia South, George Edgar and Put Murphy)

- *A Modified Delphi Approach to Predict Market Transformation Program Effects*, Proceedings of ACEEE 2000 Summer Study Conference on Energy Efficiency in Buildings, Volume 6 (with Phil Mosenthal et al.)
- *Using Targeted Energy Efficiency Programs to Reduce Peak Electrical Demand and Address Electric System Reliability Problems*, published by the American Council for an Energy Efficient Economy, November 2000 (with Steve Nadel and Fred Gordon)
- *Energy Savings Potential from Addressing Residential Air Conditioner and Heat Pump Installation Problems*, American Council for an Energy Efficient Economy, February 1999 (with John Proctor and Steve Nadel)
- *Promoting High Efficiency Residential HVAC Equipment: Lessons Learned from Leading Utility Programs*, Proceedings of ACEEE 1998 Summer Study Conference on Energy Efficiency in Buildings, Volume 2 (with Jane Peters and Denise Rouleau)
- *PowerSaver Home Program Impact Evaluation*, report to Potomac Edison, February 1998 (with Andy Shapiro, Ken Tohinaka and Karl Goetze)
- *A Tale of Two States: Detailed Characterization of Residential New Construction Practices in Vermont and Iowa*, Proceedings of ACEEE 1996 Summery Study Conference on Energy Efficiency in Buildings, Volume 2 (with Blair Hamilton, Paul Erickson, Peter Lind and Todd Presson)
- *New Smart Protocols to Avoid Lost Opportunities and Maximize Impact of Residential Retrofit Programs*, in Proceedings of ACEEE 1994 Summer Study on Energy Efficiency in Buildings (with Blair Hamilton and Ken Tohinaka
- *Economic Analysis of Woodchip Systems* and *Finding Capital to Pay for a Woodchip Heating System*, Chapters 6 and 8 in Woodchip Heating Systems: A Guide for Institutional and Commercial Biomass Installations, published by the Council of Northeastern Governors, July 1994
- *PSE&G Lost Opportunities Study: Current Residential Programs and Relationship to Lost Opportunties*, prepared for the PSE&G DSM Collaborative, June 1994 (with Blair Hamilton, Paul Berkowitz and Wayne DeForest)
- *PSE&G Lost Opportunities Study: Preliminary Residential Market Analysis*, prepared for the PSE&G DSM Collaborative, May 1994 (with Blair Hamilton, Paul Berkowitz and Wayne DeForest)
- *Long-Range Evaluation Plan for the Vermont Weatherization Assistance Program*, prepared for the Vermont Office of Economic Opportunity, February 1994 (with Blair Hamilton and Ken Tohinaka)
- *Impact Evaluation of the 1992-1993 Vermont Weatherization Assistance Program*, prepared for the Vermont Office of Economic Opportunity, December 1993 (with Blair Hamilton and Ken Tohinaka)
- *Electric Utilities and Long-Range Transport of Mercury and Other Toxic Air Pollutants*, published by the Center for Clean Air Policy, 1991
- *Coal and Emerging Energy and Environmental Policy*, in Natural Resources and Environment, 1991 (with Don Crane)

- *Acid Rain: The Problem*, in EPA Journal, January/February 1991 (with Ned Helme)
- *An Efficient Approach to Reducing Acid Rain: The Environmental Benefits of Energy Conservation*, published by the Center for Clean Air Policy, 1989
- *The Untold Story: The Silver Lining for West Virginia in Acid Rain Control*, published by the Center for Clean Air Policy, 1988
- *Midwest Coal by Wire: Addressing Regional Energy and Acid Rain Problems*, published by the Center for Clean Air Policy, 1987
- *Acid rain: Road to a Middleground Solution*, published by the Center for Clean Air Policy, 1987 (with Ned Helme)

**Public Service of New Hampshire d/b/a Eversource Energy**
**Docket No. DE 17-136**

**Date Request Received: 10/05/2018** **Date of Response: 10/19/2018**
**Request No. OCA 2-011** 
**Request from: Office of Consumer Advocate**

**Witness: Katherine W. Peters**

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**Request:**
Reference the EESE Board resolution of July 11, 2017 directing the utilities to "consider adding certain pilot projects to the Plan, e.g., geo-targeting," and to "review similar programs ongoing in other states to determine how the results of those pilot programs may inform efforts in New Hampshire."

a. If the utilities have not included any such pilot using the geo-targeting of energy efficiency in the 2019 update of the 2018-20 plan, please describe why not.
b. Please provide any review of geo-targeting or non-wire alternatives programs the utilities have now performed as a means of preparing for such efforts in New Hampshire.

**Response:**
As an initial matter, the utilities disagree with the premise of the question. For clarity, the document to which the question links is a list of recommendations made on July 11, 2017 by the EERS Committee of the EESE Board which, according to the EESE Board's July 21, 2017 minutes was adopted by the Board. As additional information, the Board was then to take those recommendations and draft a letter "to be submitted to the Commission, and copied to utilities and the EESE Board." EESE Board July 21, 2017 Minutes at page 2. It appears no recommendation letter of the EESE Board itself was ever submitted to the Commission, the utilities or the Board.

The EERS Committee recommendation adopted by the Board indicates "that the Board ***ask*** the utilities ***to consider*** adding certain pilot projects to the Plan, e.g., geo-targeting, strategic energy management, and connected devices & fixtures." Recommendation at 5 (emphases added). Thus, the EESE Board did not "direct" anything relative to pilot programs and the OCA's implication that the utilities did not abide by a directive of the EESE Board is wrong.

Furthermore, in the 17 EERS Committee meetings and 5 stakeholder workshops that took place between August 30, 2016 and July 18, 2017 there is no mention in the posted minutes or materials of any significant discussion regarding geo-targeting as a potential element of the 3-year Plan. Geo-targeting appears in the EERS Committee recommendation as an example of the type of pilot projects the Board could ask the utilities to consider including. As a topic it did not receive any of the extensive stakeholder discussion and vetting that occurred with other recommended elements that were ultimately included in the 2018-2020 Plan.

a. As to the question itself, the scope of this docket was described both on page 8 of the April 27, 2016 settlement in Docket DE 15-137 and on page 62 of Order No. 25,932 approving that settlement. That Order reads, in relevant part and with emphasis added:

We approve the Settling Parties' recommendations for an EERS process, including the pre-filing collaborative preparation of a plan for the first triennium with the assistance of a planning expert. We agree that such a process will likely result in a more efficient and less adversarial adjudicative proceeding following the plan's filing for Commission review and approval. **An *abbreviated* annual plan update process during the trienniums, like the process we currently use for the Core dockets, is appropriate and will enable the stakeholders some *flexibility to respond to developments in the energy efficiency market during that time*.**

Geo-targeting was not included as an element of the 2018-2020 Plan that was approved in Order No. 26,095. This docket is intended to be an update for the 2019 program year that would be reviewed in an abbreviated process. Accordingly, there are no new geo-targeting pilots in this update to the plan.

b. Geo-targeted energy efficiency is typically considered as part of the distribution planning process on a case by case basis. In that process multiple factors must be accounted for including not just the absolute size of the need but also when the need is occurring, the duration of the need, whether the solutions are needed due to load growth or due to end-of-life or other necessary equipment upgrades, and the potential for achieving the necessary results through energy efficiency or other non-wires alternatives. The planning must be geared toward achieving an operational outcome and in almost all instances, the wires alternative provides a more comprehensive and cost effective solution.

Review of geo-targeted energy efficiency options will continue to be a part of the distribution planning process and to the extent that it presents a viable solution for a particular situation, the utility would move forward with a discussion and planning process for implementation.

In November 2017, Liberty filed for a battery storage pilot (Docket No. DE 17-189) which included 1000 behind-the-meter Tesla Powerwall 2 installed in customer homes. The purpose of the installations was two-fold: reduce transmission costs and provide a non-wires alternative (NWA) to a circuit that was at capacity. During the course of the proceeding, the OCA provided testimony that included adding targeted energy efficiency measures to the NWA portion of the program. The Company included in its benefit cost model the targeted energy efficiency measures on its 11L1 circuit in West Lebanon as part of the development of a robust benefit cost model for the non-wires alternative portion of its battery storage pilot. Please see Attachment OCA 2-011b.

(Joint Utility Response)

**Liberty Utilities (Granite State Electric) d/b/a Liberty Utilities Proposed Battery Pilot Project**
**Benefit/Cost Analysis**

| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Year | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | |
| 2 | Batteries Installed | 1,000 | 0 | 300 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | Benefits | | | | | | | | | | | | | | | | **Total** |
| 3 | Regional Network System (RNS) rate ($/kW-year) | $117.00 | $123.00 | $129.00 | $135.00 | $141.29 | $147.88 | $154.77 | $161.98 | $169.53 | $177.43 | $185.69 | $194.35 | $203.40 | $212.88 | $222.80 | |
| 4 | Local Network System (LNS) rate( $/kW-year) | $23.57 | $24.46 | $25.17 | $25.42 | $26.61 | $27.85 | $29.14 | $30.50 | $31.92 | $33.41 | $34.97 | $36.60 | $38.30 | $40.09 | $41.96 | |
| 5 | Avoided Capacity Cost rate ($/kW-year) | $100.00 | $73.90 | $59.90 | $57.60 | $58.80 | $61.20 | $65.70 | $71.20 | $76.90 | $82.50 | $88.10 | $83.90 | $82.50 | $88.10 | $83.90 | |
| 6 | Regional Network System (RNS) Charges | $438,750 | $461,250 | $483,750 | $506,250 | $529,841 | $554,532 | $580,373 | $607,418 | $635,724 | $665,349 | $587,723 | $539,315 | $324,430 | $418,315 | $0 | **$7,333,021** |
| 7 | Local Network System (LNS) Charges | $88,373 | $91,733 | $94,380 | $95,330 | $99,773 | $104,422 | $109,288 | $114,381 | $119,711 | $125,290 | $110,672 | $101,557 | $89,819 | $78,772 | $0 | **$1,423,503** |
| 8 | Avoided Capacity Costs | $375,000 | $277,125 | $224,625 | $216,000 | $220,500 | $229,500 | $246,375 | $267,000 | $288,375 | $309,375 | $278,837 | $232,823 | $193,463 | $173,117 | $0 | **$3,532,113** |
| | NWA Distribution Upgrade | $0 | $99,723 | $96,363 | $93,127 | $90,007 | $86,994 | $84,079 | $81,255 | $78,516 | $75,790 | $73,065 | $70,340 | $67,614 | $64,889 | $62,163 | **$1,123,925** |
| | Targeted Energy Efficiency | $0 | $118,762 | $118,762 | $118,762 | $118,762 | $118,762 | $118,762 | $118,762 | $118,762 | $118,762 | $118,762 | $118,762 | $118,762 | $118,762 | $118,762 | $1,662,674 |
| 9 | Total Benefits | $902,123 | $1,048,593 | $1,017,880 | $1,029,470 | $1,058,884 | $1,094,210 | $1,138,878 | $1,188,817 | $1,241,089 | $1,294,566 | $1,169,059 | $1,062,796 | $794,088 | $853,855 | $180,926 | **$15,075,235** |
| | Costs | | | | | | | | | | | | | | | | |
| 10 | Revenue Requirement - Batteries | ($1,358,220) | ($1,247,334) | ($1,184,055) | ($1,115,240) | ($1,042,440) | ($959,814) | ($877,132) | ($806,850) | ($736,541) | ($653,887) | $0 | $0 | $0 | $0 | $0 | **($9,981,514)** |
| 11 | Revenue Requirement - Cell Based Meters | ($45,291) | ($43,201) | ($41,500) | ($39,795) | ($38,086) | ($36,374) | ($34,658) | ($32,940) | ($31,192) | ($29,438) | ($27,684) | ($25,930) | ($24,177) | ($22,423) | $0 | **($472,689)** |
| 12 | Monthly Cellular Reading Cost | ($36,000) | ($36,000) | ($36,000) | ($36,000) | ($36,000) | ($36,000) | ($36,000) | ($36,000) | ($36,000) | ($36,000) | ($34,800) | ($33,600) | ($30,600) | ($27,600) | $0 | **($486,600)** |
| 13 | Cogsdale Programming Costs | ($102,185) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | **($102,185)** |
| 14 | NEM Credit for battery | ($17,379) | ($16,857) | ($16,336) | ($15,815) | ($15,293) | ($14,772) | ($14,251) | ($13,729) | ($13,208) | ($12,687) | ($12,165) | ($11,644) | ($11,122) | ($10,601) | $0 | **($195,860)** |
| | Energy Efficiency | ($572,066) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | **($572,066)** |
| 15 | Meter MV-90 Programming Costs | ($107,500) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | **($107,500)** |
| 16 | Total Costs | ($2,238,641) | ($1,343,393) | ($1,277,891) | ($1,206,850) | ($1,131,819) | ($1,046,959) | ($962,041) | ($889,519) | ($816,941) | ($732,012) | ($74,649) | ($71,174) | ($65,899) | ($60,624) | $0 | ($11,918,413) |
| 17 | Net Benefit to All Customers | ($1,336,518) | ($294,800) | ($260,011) | ($177,380) | ($72,936) | $47,251 | $176,837 | $299,298 | $424,148 | $562,555 | $1,094,410 | $991,622 | $728,190 | $793,231 | $180,926 | **$3,156,822** |

| | Net Present Value Calculation | |
|---|---|---|
| 18 | Required Rate of Return | 7.69% |
| 19 | Net Present Value of Option | $411,941 |
| 20 | Net Present Value of Benefits | $8,964,128 |
| 21 | Net Present Value of Costs | ($8,552,187) |

1 Year of installation
2 Total units in pilot
3 Based on ISO-NE forecast
4 Based on previous bills from National Grid
5 AESC 2018 Wholesale Capacity Values Cleared (FCA price), column j on p 273
6 Line 3 x amount of kW reduced
7 Line 4 x amount of kW reduced
8 Line 5 x amount of kW reduced at ISO NE concident peak
9 Sum of lines 3 through 8
10 Battery revenue requirement
11 Meter revenue requirement
12 Liberty's estimated costs for reading meters
13 Liberty's estimated programming costs associated with billing TOU rates
14 Net Metering Credit provided to customers when batteries are exported to the grid
15 Liberty's estimated costs for programming meters
16 Sum of lines 10 through 15
17 Line 9 - Line 16
18 After-tax discount rate
19 Net Present Value calculation of net benefits using discount rate in Line (20) and net benefits (or costs ) in line (19)
20 Net Present Value calculation of  benefits using discount rate in Line (20) and  benefits in line (12)
21 Net Present Value calculation of costs using discount rate in Line (20) and costs in line (18)

**Public Service of New Hampshire d/b/a Eversource Energy**
**Docket No. DE 17-136**

**Date Request Received: 10/05/2018** **Date of Response: 10/22/2018**
**Request No. OCA 2-014** 
**Request from: Office of Consumer Advocate**

**Witness: Katherine W. Peters**

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**Request:**
Reference Eversource's Marginal Cost of Service Study filed with the Commission on July 16, 2018, stating "The MCOS study uses available information of regional forecasts of annual peak load growth, along with information on known industrial step load additions at specific bulk stations to estimate the share of the system potentially subject to requiring growth-related expansion over the full five-year period as new load materializes. A review of the station loads and nameplate ratings revealed that some of the high-growth distribution areas will have ample station capacity to serve peak loads during the study period," and that "[t]he Company anticipates that station capacity expansion will be needed in a number of location in order to meet the minimum planning criteria," and that "[t]he MCOS builds upon an in-depth review of the Company's budgeted investments for the upcoming planning period (2019 - 2023). Our review identified specific bulk station and distribution substation expansion projects. EI reviewed the nature of these projects and identified the cost associated with capacity expansion in capital planning. These projects generally involve replacement of existing substation transformers with one (or two) larger transformers. These investments intend to address existing or expected overload conditions, serve new step industrial or commercial load additions, and/or offload nearby substations." Please provide all supporting materials relative the analysis performed to determine the marginal cost of capacity constrained areas, including but not limited to the above-mentioned:

a. Eversource's budgeted investments for the upcoming planning period (2019-2023).
b. Information on regional forecasts of annual peak load growth;
c. Information on known industrial step load additions at specific bulk stations;
d. An estimation of the share of the system potentially subject to requiring growth-related expansion over the full five-year period as new load materializes;
e. The review of the station loads and nameplate ratings;
f. On a project by project basis, the specific bulk station and distribution substation capacity enhancements that will be needed in order to meet the minimum planning criteria, along with a description of that criteria, and the current peak loading as a percentage of that criteria, and projected peak loading between 2019 and 2023, and the cost of the investment. Please provide this data in excel format, building upon the template format utilized in Southern California Edison's Grid Needs Assessment.

**Response:**
Eversource objects to this data request on the grounds that the question requests data or information which is not relevant to the issues in this docket concerning the approval of the 2019 plan update. As described both on page 8 of the April 27, 2016 settlement in Docket DE 15-137 and on page 62 of Order No. 25,932 approving that settlement. That Order reads, in relevant part and with emphasis added:

We approve the Settling Parties' recommendations for an EERS process, including the pre-filing collaborative preparation of a plan for the first triennium with the assistance of a planning expert. We agree that such a process will likely result in a more efficient and less adversarial adjudicative proceeding following the plan's filing for Commission review and approval. **An *abbreviated* annual plan update process during the trienniums, like the process we currently use for the Core dockets, is appropriate and will enable the stakeholders some *flexibility to respond to developments in the energy efficiency market during that time*.**

In that this docket was intended to be an abbreviated review of an update to existing programs, which do not have geo-targeted investments as part of the proposals, the information about specific projects is not relevant to this docket. Further, and with respect to part f, Eversource objects on the grounds that the question requires speculation and that Eversource is not obligated to create a new analysis or report on behalf of another. Subject to, and without waiving, the above objections, Eversource will provide a response.

Please refer to the attachments, provided in Excel format, as follows:

a. See Attachment OCA 2-014a for the Marginal Investment Bulk and Substation Cost
b. See OCA 2-014b for 2018-2013 Forecast station peak loads by region and comparison with station ratings
c. See OCA 2-014c for Step Load Additions in Bulk Stations
d. See part b., for bulk substations and Attachment OCA 2-014d for Distribution Substation Capacity Analysis
e. See part b.
f. See part a.

Docket No. DE 17-136
New Hampshire Electric and Gas Utilities
OCA Data Requests - Set 2
Attachment OCA 2-014a
Page 1

## EVERSOURCE ENERGY COMPANY
## DERIVATION OF MARGINAL BULK STATION AND DISTRIBUTION STATION AND LINE INVESTMENT

| | | Upstream Bulk Station | Distribution Substation |
|---|---|---|---|
| (1) | Marginal Station Investment per kW of Added Project Capacity in growth areas, 2019-2023 (2019$ /kW) | $256.47 | $331.39 |
| (2) | Station Nameplate Rating Percent Margin over Station Load | 33.0% | - |
| (3) | Marginal investment per kW of Station Peak in capacity constrained areas, 2019 - 2023 period, $/kW | $341.11 | $331.39 |
| (4) | Share of total system load that uses station type | 98.3% | 16.67% |
| (5) | Share of total peak load served from stations in areas with expected capacity expansion (2019-2023) | 33.51% | 23.54% |
| (6) | System-Wide Marginal Station Investment (2019 $ /kW) | **$112.32** | **$13.00** |

Note: Line 4 reflects that CVEC loads are served from bulk stations in Vermont, and that only a share of the Company's loads are fed from distribution substations.

**EVERSOURCE ENERGY COMPANY**
**DISTRIBUTION CAPITAL BUDGET (2018 - 2023)**

**BULK STATIONS - PEAK-LOAD RELATED PLANNED INVESTMENT**

| Region | Project | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | Notes |
|---|---|---|---|---|---|---|---|---|
| | | | | (000 $) | | | | |
| N.A | Anticipated Station Replacement | | | 1,000.0 | 6,000 | 20,000 | 20,000 | Potential capacity additions (investment intended for reliability capacity or asset condition projects; no certain location) |
| Eastern | Dover S/S | 767.0 | 2,000 | 2,000.0 | | | | Rebuild replace two 44.8 MVA with two 62.5 MVA. Dollars adjusted to exclude the share of the costs unrelated to load growth (e.g. costs to allow for bus restoral system plus bus tie breaker, rela |
| Central | Huse Rd Transformer Replacement | | | 2,000 | 2,500 | | | Replace two 44.8 MVA with two 62.5 MVA. Year 2021 dollars exclude the share of the work to allow for bus restoral system plus bus tie breaker, relays, etc. |
| Eastern | Portsmouth S/S | | 1,000 | 2,000 | - | - | - | Replace 44 MVA with 62.5 MW, add a new 62.5 MVA substation (only cost of first substation has been included; the second transformer under this project has not been inluded since it will be use |
| Western | Monadnock SS | | 945.0 | 2,500.0 | 2,500 | | | Replace existing transformers with larger units |
| | **Inflation Adjustment** | - | 0.0212 | 0.0205 | 0.0203 | 0.0202 | 0.0203 | |

| Region | Project | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | Total (2019$) | Existing Capacity | New | Added * | Inv/ Added Capacity | Average Cost per kW added | Capacity share | 2023 forecasted peak load | Load reduction needed by 2023 using 75% criteria |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | (000 $), 2019$ | | | | | | MW | | $/kW | $/kW | | MVA | MVA |
| | Anticipated Station Replacement | - | - | 980 | 5,763 | 18,829 | 18,455 | 44,027 | | 132.0 | 132.0 | $333.5 | | 0.55 | n/a | |
| Eastern | Dover S/S | 783 | 2,000 | 1,960 | - | - | - | 4,743 | 90 | 125.0 | 35.4 | $134.0 | | 0.15 | 84.50 | **17.3** |
| Central | Huse Rd Transformer Replacement | - | - | 1,960 | 2,401 | - | - | 4,361 | 93 | 125.0 | 32.2 | $135.4 | | 0.13 | 77.10 | **7.5** |
| Eastern | Portsmouth S/S | - | 1,000 | 1,960 | - | - | - | 2,960 | 45 | 62.5 | 17.7 | $167.2 | | 0.07 | 43.10 | **9.5** |
| Western | Monadnock SS | - | 945 | 2,450 | 2,401 | - | - | 5,796 | 20 | 44.0 | 24.0 | $241.5 | | 0.10 | 39.80 | **3.8** |
| | | | | | | | **Total** | **61,887** | | | | | **$256.47** | 1.00 | **244.50** | **38.10** |

to cover expected peak demand in n-1 conditions

**EVERSOURCE ENERGY COMPANY**
**DISTRIBUTION STATION CAPITAL BUDGET (2019 - 2023)**

**DISTRIBUTION SUBSTATIONS - PEAK-LOAD RELATED PLANNED INVESTMENT**

| Region | Project | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | Notes |
|---|---|---|---|---|---|---|---|---|
| | | | | *(000 $)* | | | | |
| n/a | Maintain Voltage - PSNH | 700 | 700 | 700 | 700 | 700 | 700 | Location not identified; capacity added not defined -- driven by future load needs |
| n/a | Peak Load Dist Line Plug | - | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | Location not identified; capacity added not defined -- driven by future load needs |
| n/a | ROW Peak Load Plug | | 500 | 500 | 500 | 500 | 500 | Location not identified; capacity added not defined -- driven by future load needs |
| Northern | River Road S/S | 444 | 2,000 | | | | | Additional 9 MVA capacity; industrial load driving the project, as well as the need to back up load from a neighbor substation through circui |
| n/a | Substation Peak Load Plug | | - | 400 | 400 | 1,600 | 1,600 | Replace two 5 MVA with 20 MVA subs; dollars adjusted from original budget --only 40% of the amount was related to capacity additions |
| Northern | Weirs SS | | | 1,000 | 2,000 | | | Replace 1.5 MVA with a 10 MVA. Project is used to off-load Black Brook S/S and to provide a backup source to some of the load fed from Bl |
| | **Inflation Adjustment** | | 0.0212 | 0.0205 | 0.0203 | 0.0202 | 0.0203 | |

| Region | Project | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | Total (2019$) | Existing Capacity | New | Added | Inv/ Added Capacity | Average Cost per kW added | Capacity shares |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | *(000 $), $2019* | | | | | | *MW* | | *$/kW* | *$/kW* | |
| Northern | River Road S/S | 453 | 2,000 | - | - | - | - | **2,453** | 5.0 | 14.0 | 9.0 | 272.60 | | 0.33 |
| n/a | Substation Peak Load Plug | - | - | 392 | 384.20 | 1,506 | 1,476 | **3,759** | 10.0 | 20.0 | 10.0 | 375.89 | | 0.36 |
| Northern | Weirs SS | - | - | 980 | 1,921 | - | - | **2,901** | 1.5 | 10.0 | 8.5 | 341.29 | | 0.31 |
| | | | | | | | **Total** | **9,113.29** | | | | | **$331.39** | **1.0** |

**Northern Region - Coincident 90/10 Summer Peak Forecast (MW)**

| Year | Ashland | | Beebe River | | Berlin | | Laconia | | Lost Nation | | No. Woodstock | | Pemigew asset | | Saco Valley | | Webster | | White Lake | | Whitefiel d | | Total Northern |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | 35.7 | | 19.0 | | 16.5 | | 61.6 | | 10.8 | | 9.4 | | 22.8 | | 19.7 | | 35.1 | | 44.2 | | 21.8 | | 296.7 |
| 2019 | 36.0 | 0.7% | 19.2 | 0.9% | 16.6 | 0.8% | 62.0 | 0.7% | 10.9 | 0.9% | 9.5 | 1.0% | 23.0 | 0.8% | 19.8 | 0.8% | 35.3 | 0.7% | 44.5 | 0.7% | 21.9 | 0.8% | 298.9 |
| 2020 | 36.1 | 0.4% | 19.3 | 0.5% | 16.7 | 0.4% | 62.2 | 0.4% | 11.0 | 0.5% | 9.5 | 0.5% | 23.1 | 0.4% | 19.9 | 0.4% | 35.5 | 0.4% | 44.7 | 0.4% | 23.0 | 5.0% | 301.0 |
| 2021 | 36.3 | 0.6% | 19.4 | 0.7% | 16.8 | 0.7% | 62.5 | 0.5% | 11.1 | 0.7% | 9.6 | 0.8% | 23.2 | 0.6% | 20.1 | 0.6% | 35.7 | 0.6% | 44.9 | 0.5% | 23.2 | 0.6% | 302.8 |
| 2022 | 36.6 | 0.8% | 19.6 | 1.0% | 17.0 | 0.9% | 63.0 | 0.7% | 11.2 | 1.0% | 9.7 | 1.1% | 23.4 | 0.8% | 20.2 | 0.9% | 36.0 | 0.8% | 45.3 | 0.7% | 23.3 | 0.8% | 305.2 |
| 2023 | 36.8 | 0.7% | 19.8 | 0.9% | 17.1 | 0.8% | 63.4 | 0.6% | 11.3 | 0.9% | 9.8 | 1.0% | 23.6 | 0.7% | 20.4 | 0.8% | 36.2 | 0.7% | 45.6 | 0.7% | 23.5 | 0.7% | 307.4 |
| 18-23 Growth | 3.12% | | 3.97% | | 3.67% | | 2.92% | | 3.94% | | 4.45% | | 3.38% | | 3.50% | | 3.13% | | 3.03% | | 8.00% | | 3.63% |

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *2018* | *113.0* | | *7.7* | | *59.3* | | *6.0* | | *42.0* | | *45.7* | | *13.4* | | *47.7* | | *71.0* | | *32.1* | | *39.0* | | *21.3* | | *498.3* |
| *2019* | *113.7* | 0.6% | *7.7* | 0.7% | *60.7* | 2.3% | *6.0* | 0.0% | *42.3* | 0.6% | *46.8* | 2.4% | *13.5* | 0.9% | *48.0* | 0.7% | *71.5* | 0.6% | *32.3* | 0.6% | *39.3* | 0.7% | *21.5* | 0.8% | *503.3* |
| *2020* | *114.1* | 0.3% | *7.8* | 0.4% | *60.9* | 0.3% | *6.0* | 0.0% | *42.4* | 0.3% | *47.0* | 0.4% | *13.6* | 0.5% | *48.2* | 0.4% | *71.7* | 0.3% | *32.4* | 0.3% | *39.4* | 0.4% | *21.5* | 0.4% | *505.1* |
| *2021* | *114.7* | 0.5% | *7.8* | 0.5% | *61.2* | 0.5% | *6.0* | 0.0% | *42.6* | 0.5% | *47.3* | 0.5% | *13.7* | 0.7% | *48.5* | 0.5% | *72.1* | 0.5% | *32.6* | 0.5% | *39.6* | 0.6% | *21.7* | 0.6% | *507.7* |
| *2022* | *115.5* | 0.7% | *7.9* | 0.7% | *61.7* | 0.7% | *6.0* | 0.0% | *42.9* | 0.7% | *47.6* | 0.7% | *13.8* | 1.0% | *48.8* | 0.7% | *72.6* | 0.7% | *32.8* | 0.7% | *39.9* | 0.7% | *21.9* | 0.8% | *511.2* |
| *2023* | *116.2* | 0.6% | *7.9* | 0.6% | *62.1* | 0.6% | *6.0* | 0.0% | *43.2* | 0.6% | *47.9* | 0.7% | *13.9* | 0.9% | *49.1* | 0.7% | *73.0* | 0.6% | *33.0* | 0.6% | *40.2* | 0.7% | *22.0* | 0.8% | *514.5* |
| 18-23 Grov | 2.79% | | 2.93% | | 4.56% | | 0.00% | | 2.80% | | 4.76% | | 3.91% | | 3.00% | | 2.83% | | 2.70% | | 3.08% | | 0.65% | | 0.59% |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *2018* | *15.7* | | *38.3* | | *37.9* | | *21.3* | | *38.6* | | *7.8* | | *159.7* |
| *2019* | *15.8* | 0.8% | *38.5* | 0.7% | *38.9* | 2.5% | *21.5* | 0.7% | *38.9* | 0.7% | *7.9* | 0.8% | *161.5* |
| *2020* | *15.9* | 0.4% | *38.7* | 0.4% | *39.0* | 0.4% | *21.6* | 0.4% | *39.1* | 0.4% | *7.9* | 0.4% | *162.1* |
| *2021* | *16.0* | 0.7% | *38.9* | 0.6% | *39.2* | 0.5% | *21.7* | 0.6% | *39.3* | 0.6% | *8.0* | 0.7% | *163.1* |
| *2022* | *16.2* | 0.9% | *39.2* | 0.8% | *39.5* | 0.7% | *21.9* | 0.8% | *39.6* | 0.7% | *8.0* | 0.9% | *164.4* |
| *2023* | *16.3* | 0.8% | *39.4* | 0.7% | *39.8* | 0.7% | *22.1* | 0.7% | *39.8* | 0.7% | *8.1* | 0.8% | *165.5* |
| 18-23 Growth | 3.72% | | 3.09% | | 4.93% | | 3.33% | | 3.08% | | 3.72% | | 3.65% |

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *2018* | *63.7* | | *68.8* | | *83.7* | | *11.3* | | *75.1* | | *35.3* | | *51.5* | | *55.0* | | *57.2* | | *35.3* | | *66.1* | | *14.6* | | 617.5 |
| *2019* | *65.1* | 2.2% | *69.2* | 0.6% | *84.2* | 0.6% | *11.3* | 0.6% | *75.5* | 0.6% | *35.5* | 0.6% | *54.1* | 5.0% | *55.3* | 0.6% | *57.5* | 0.6% | *35.5* | 0.6% | *66.5* | 0.6% | *14.7* | 0.6% | 624.5 |
| *2020* | *66.3* | 1.8% | *69.4* | 0.3% | *84.9* | 0.8% | *11.4* | 0.3% | *75.8* | 0.3% | *35.6* | 0.3% | *54.2* | 0.3% | *55.8* | 0.8% | *57.7* | 0.3% | *35.6* | 0.3% | *66.7* | 0.3% | *14.7* | 0.3% | 628.2 |
| *2021* | *66.6* | 0.5% | *69.7* | 0.5% | *85.9* | 1.2% | *11.4* | 0.5% | *76.1* | 0.5% | *35.8* | 0.5% | *54.5* | 0.4% | *56.5* | 1.2% | *58.0* | 0.5% | *35.8* | 0.5% | *67.0* | 0.5% | *14.8* | 0.5% | 632.1 |
| *2022* | *67.0* | 0.6% | *70.2* | 0.6% | *86.3* | 0.4% | *11.5* | 0.6% | *76.6* | 0.6% | *36.0* | 0.6% | *54.8* | 0.6% | *56.7* | 0.4% | *58.3* | 0.6% | *36.0* | 0.6% | *67.5* | 0.6% | *14.9* | 0.6% | 635.8 |
| *2023* | *67.4* | 0.6% | *70.6* | 0.6% | *86.8* | 0.6% | *11.5* | 0.6% | *77.1* | 0.6% | *36.2* | 0.6% | *55.1* | 0.5% | *57.1* | 0.6% | *58.7* | 0.6% | *36.3* | 0.7% | *67.9* | 0.6% | *15.0* | 0.6% | 639.6 |
| 18-23 Growth | 5.76% | | 2.63% | | 3.79% | | 2.58% | | 2.63% | | 2.62% | | 6.99% | | 3.79% | | 2.63% | | 2.79% | | 2.63% | | 2.60% | | 3.59% |

| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *2018* | *23.6* | | *79.1* | | *75.2* | | *11.4* | | *39.0* | | *41.1* | | *24.0* | | *61.9* | | *30.6* | | *34.5* | | *420.3* |
| *2019* | *23.7* | 0.6% | *81.0* | 2.5% | *75.6* | 0.6% | *11.9* | 5.0% | *39.2* | 0.6% | *42.4* | 3.0% | *24.7* | 2.7% | *62.3* | 0.6% | *30.8* | 0.6% | *34.6* | 0.6% | *426.2* |
| *2020* | *23.8* | 0.3% | *82.2* | 1.5% | *76.3* | 1.0% | *12.0* | 0.3% | *39.4* | 0.3% | *42.5* | 0.3% | *25.2* | 2.3% | *62.5* | 0.3% | *30.9* | 0.3% | *34.7* | 0.3% | *429.5* |
| *2021* | *23.9* | 0.5% | *83.6* | 1.6% | *76.7* | 0.4% | *12.0* | 0.4% | *39.5* | 0.5% | *42.7* | 0.4% | *25.3* | 0.4% | *62.8* | 0.5% | *31.0* | 0.5% | *34.9* | 0.4% | *432.4* |
| *2022* | *24.0* | 0.6% | *84.1* | 0.6% | *77.1* | 0.6% | *12.1* | 0.6% | *39.8* | 0.6% | *42.9* | 0.6% | *25.5* | 0.6% | *63.2* | 0.6% | *31.2* | 0.6% | *35.1* | 0.6% | *434.9* |
| *2023* | *24.2* | 0.6% | *84.5* | 0.5% | *77.6* | 0.6% | *12.2* | 0.5% | *40.0* | 0.6% | *44.1* | 2.8% | *25.6* | 0.5% | *63.5* | 0.6% | *31.4* | 0.6% | *35.3* | 0.5% | *437.3* |
| 18-23 Grov | 2.57% | | 6.88% | | 3.20% | | 6.86% | | 2.60% | | 7.17% | | 6.66% | | 2.57% | | 2.62% | | 2.40% | | 4.05% |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *2018* | *298.7* | | *496.9* | | *163.1* | | *611.6* | | *425.4* | | *1785.7* | *1920.8* | *2255.9* |
| *2019* | *300.9* | 0.7% | *502.0* | 1.0% | *165.0* | 1.1% | *618.4* | 1.1% | *431.4* | 1.4% | *1805.7* | *1941.6* | *2278.7* |
| *2020* | *303.1* | 0.7% | *503.7* | 0.3% | *165.6* | 0.4% | *621.9* | 0.6% | *434.7* | 0.8% | *1815.3* | *1951.7* | *2290.0* |
| *2021* | *305.0* | 0.6% | *506.3* | 0.5% | *166.5* | 0.6% | *625.7* | 0.6% | *437.6* | 0.7% | *1824.5* | *1961.7* | *2301.9* |
| *2022* | *307.4* | 0.8% | *509.9* | 0.7% | *167.8* | 0.8% | *629.1* | 0.5% | *440.2* | 0.6% | *1835.8* | *1974.0* | *2316.8* |
| *2023* | *309.7* | 0.7% | *513.2* | 0.6% | *169.0* | 0.7% | *632.6* | 0.6% | *442.7* | 0.6% | *1849.7* | *1988.7* | *2333.7* |
| 18-23 Growth | 3.66% | | 3.27% | | 3.60% | | 3.43% | | 4.05% | | 3.58% | 3.54% | 3.45% |

| | | |
|---|---|---|
| Southern | 143.0 | 19% |
| Western | 79.2 | 10.6% |
| Central | 319.2 | 42.7% |
| Eastern | 206.2 | 27.6% |
| TOTAL | **747.6** | **100%** |

Note: "Capacity Need Area" is defined as total peak load at substations where peak load is expected to exceed 75% of transformer nameplate capacity by 2023

| | **Year 2023** | |
|---|---|---|
| 2023 CP w/o wholesale | 1,849.7 | Eversource's 2023 CP projection (System1) |
| NEHC + Municipal CP | 139.06 | Includes NHEC, Ashland, New Hampton and Wolfeboro |
| Unitil + Vermont | 344.96 | Resales and CVEC |
| Subtotal with Wholesale | 2,333.69 | |
| 2023 NCP estimate | 2,408.4 | Adjustment to account for the winter-peaking stations' higher max loads in the winter |
| | | |
| 2023 Total system NCP | **2,408.4** | |
| *% of Constrained Load over Total NCP* | *31.04%* | |

**Step Load Additions Summary (MW)**

| Substation | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|
| **Central** | | | | |
| Bedford | | 1.0 | 1.0 | |
| **Eastern** | | | | |
| Dover | 0.5 | 1.5 | 1.0 | 1.0 |
| Madbury | | | 0.5 | |
| Mill Pond | 0.5 | 0.5 | | |
| Portsmouth | 1.0 | 1.0 | | |
| Resistance | 0.5 | 0.5 | 0.5 | |
| Rochester | 1.0 | | | |
| **Northern** | | | | |
| Lost Nation | 1.0 | | | |
| Whitefield | | | 1.0 | |
| **Southern** | | | | |
| Bridge St | 2.0 | | | |
| Hudson | | 0.8 | | |
| Long Hill | 1.2 | | | |
| Mammoth Rd. | 1.6 | 3.3 | | |
| **Western** | | | | |
| Monadnock | | 0.7 | | |
| North Keene | 0.8 | | | |
| **Total** | **10.1** | **9.3** | **4.0** | **1.0** |

**Non-bulk Distribution Substations**

| Substation Name | Xfmr Designatio | AWC | Pri kV | Sec kV | Nameplate Rating MVA | Year 2017 Peak Load (kW)_ | 2017 Weather-Normalized Load MW | 2017 Capacity/Load ratios MW | 2017 excess load in constrained substations MW | 2018 known Ind. Additions | 2018 WN Peak Sub Loads | 2019 - 23 known ind. load additions | 2023 Station Peak Load with Ind. Additions MW | 2023 Capacity/Load Ratio | 2023 Capacity-constrained Load MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Salmon Falls | 51 | Rochester | 13.2 | 4.16 | 1.5 | 1,310 | 1.40 | 1.07 | na | | 1.41 | | 1.45 | 1.04 | - |
| Blue Hill | 97 | Nashua | 34.5 | 4.16 | 6.25 | 1,808 | 1.93 | 3.24 | na | | 1.94 | | 1.99 | 3.13 | - |
| Colebrook | 5 | Lancaster | 34.5 | 4.16 | 3.75 | 1,875 | 2.00 | 1.88 | na | | 2.01 | | 2.07 | 1.81 | - |
| Community St. | 58 | Berlin | 34.5 | 4.16 | 6.25 | 2,130 | 2.27 | 2.75 | na | | 2.28 | | 2.35 | 2.66 | - |
| Community St. | 43 | Berlin | 34.5 | 4.16 | 6.25 | 2,310 | 2.46 | 2.54 | na | | 2.48 | | 2.55 | 2.45 | - |
| Edgeville | 16 | Nashua | 34.5 | 4.16 | 6.25 | 2,040 | 2.18 | 2.87 | na | | 2.19 | | 2.25 | 2.78 | - |
| Foyes Corner | 2 | Portsmouth | 34.5 | 4.16 | 3.75 | 2,500 | 2.67 | 1.41 | na | 0.50 | 3.18 | 0.50 | 3.77 | 0.99 | 3.77 |
| Franklin | 39 | Tilton | 34.5 | 4.16 | 6.25 | 3,125 | 3.33 | 1.88 | na | | 3.35 | | 3.45 | 1.81 | - |
| Front St. | 9 | Nashua | 34.5 | 4.16 | 8.4 | 4,200 | 4.48 | 1.88 | na | | 4.50 | | 4.63 | 1.81 | - |
| Goffstown | 45 | Bedford | 34.5 | 4.16 | 1.5 | 1,500 | 1.60 | 0.94 | 0.10 | - | 1.61 | 0.15 | 1.80 | 0.83 | 1.80 |
| Messer St | 38 | Tilton | 34.5 | 4.16 | 3.75 | 1,875 | 2.00 | 1.88 | na | | 2.01 | | 2.07 | 1.81 | - |
| Milford | 231 | Milford | 34.5 | 4.16 | 1.5 | 750 | 0.80 | 1.88 | na | | 0.80 | | 0.83 | 1.81 | - |
| Millyard | 18 | Nashua | 34.5 | 4.16 | 6.25 | 2,544 | 2.71 | 2.30 | na | | 2.73 | | 2.81 | 2.23 | - |
| Millyard | 17 | Nashua | 34.5 | 4.16 | 6.25 | 3,655 | 3.90 | 1.60 | na | | 3.92 | | 4.03 | 1.55 | - |
| Newmarket | 13 | Epping | 34.5 | 4.16 | 3.75 | 1,110 | 1.18 | 3.17 | na | | 1.19 | | 1.22 | 3.06 | - |
| Newport | 42 | Newport | 34.5 | 4.16 | 3.75 | 2,093 | 2.23 | 1.68 | na | | 2.24 | | 2.31 | 1.62 | - |
| No. Dover | 41 | Rochester | 34.5 | 4.16 | 3.75 | 3,070 | 3.27 | 1.15 | na | | 3.29 | | 3.39 | 1.11 | - |
| No. Union St. | 29 | Manchester | 34.5 | 4.16 | 3.75 | 2,520 | 2.69 | 1.40 | na | | 2.70 | | 2.78 | 1.35 | - |
| Pittsfield | 90 | Tilton | 34.5 | 4.16 | 3.75 | 2,770 | 2.95 | 1.27 | na | | 2.97 | | 3.06 | 1.23 | - |
| Portland St. | 341 | Rochester | 34.5 | 4.16 | 6.25 | 2,900 | 3.09 | 2.02 | na | | 3.11 | | 3.20 | 1.95 | - |
| Ronald St. | 15 | Manchester | 34.5 | 4.16 | 5 | 2,350 | 2.51 | 2.00 | na | | 2.52 | | 2.59 | 1.93 | - |
| Rye | 5 | Portsmouth | 34.5 | 4.16 | 3.75 | 3,260 | 3.48 | 1.08 | na | | 3.50 | | 3.60 | 1.04 | - |
| Signal St. | 28 | Rochester | 34.5 | 4.16 | 3.75 | 2,100 | 2.24 | 1.67 | na | | 2.25 | | 2.32 | 1.62 | - |
| So. Laconia | 47 | Tilton | 34.5 | 4.16 | 3.75 | 1,875 | 2.00 | 1.88 | na | | 2.01 | | 2.07 | 1.81 | - |
| So. Manchester | 141 | Manchester | 34.5 | 4.16 | 10.5 | 5,340 | 5.69 | 1.84 | na | | 5.73 | | 5.89 | 1.78 | - |
| Souhegan | 7 | Milford | 34.5 | 4.16 | 3.75 | 1,460 | 1.56 | 2.41 | na | | 1.57 | | 1.61 | 2.33 | - |
| Tate Rd. | 422 | Rochester | 34.5 | 4.16 | 1.5 | 990 | 1.06 | 1.42 | na | | 1.06 | | 1.09 | 1.37 | - |
| Tate Rd. | 421 | Rochester | 34.5 | 4.16 | 2.5 | 1,850 | 1.97 | 1.27 | na | | 1.98 | | 2.04 | 1.22 | - |
| Tilton | 37 | Tilton | 34.5 | 4.16 | 3 | 1,920 | 2.05 | 1.47 | na | | 2.06 | | 2.12 | 1.42 | - |
| Twombley St. | 43 | Rochester | 34.5 | 4.16 | 2.8 | 2,080 | 2.22 | 1.26 | na | | 2.23 | | 2.29 | 1.22 | - |
| Valley St. | 22 | Manchester | 34.5 | 4.16 | 6.25 | 7,420 | 7.91 | 0.79 | 1.66 | | 7.96 | | 8.19 | 0.76 | 8.19 |
| W. Milford | 30 | Milford | 34.5 | 4.16 | 2.8 | 1,440 | 1.54 | 1.82 | na | | 1.54 | | 1.59 | 1.76 | - |
| Ash St. | 26 | Derry | 34.5 | 12.47 | 10.5 | 3943 | 4.20 | 2.50 | na | | 4.23 | | 4.35 | 2.41 | - |
| Black Brook | 11 | Tilton | 34.5 | 12.47 | 10.5 | 6710 | 7.15 | 1.47 | na | | 7.20 | | 7.40 | 1.42 | - |
| Bristol | 20 | Tilton | 34.5 | 12.47 | 12.5 | 3,647 | 3.89 | 3.21 | na | | 3.91 | | 4.02 | 3.11 | - |
| Brown Ave. | 7 | Manchester | 34.5 | 12.47 | 5.25 | 2,950 | 3.15 | 1.67 | na | | 3.16 | | 3.25 | 1.61 | - |
| Chichester | 30 | Tilton | 34.5 | 12.47 | 1.5 | 750 | 0.80 | 1.88 | na | | 0.80 | | 0.83 | 1.81 | - |
| Contoocook | 37 | Hillsboro | 34.5 | 12.47 | 3.75 | 2,710 | 2.89 | 1.30 | na | | 2.91 | | 2.99 | 1.25 | - |
| Ctr. Ossipee | 19W1 | Chocorua | 34.5 | 12.47 | 3.75 | 2,687 | 2.86 | 1.31 | na | | 2.88 | | 2.96 | 1.26 | - |
| Ctr. Ossipee | 19W2 | Chocorua | 34.5 | 12.47 | 3.75 | 2,970 | 3.17 | 1.18 | na | | 3.19 | | 3.28 | 1.14 | - |
| Cutts St. | 15 | Portsmouth | 34.5 | 12.47 | 3.75 | 3,487 | 3.72 | 1.01 | na | 1.00 | 4.74 | 1.00 | 5.88 | 0.64 | 5.88 |
| Dunbarton Rd. | 21 | Manchester | 34.5 | 12.47 | 2.5 | 1,899 | 2.02 | 1.23 | na | | 2.04 | | 2.10 | 1.19 | - |
| E. Northwood | 63 | Epping | 34.5 | 12.47 | 3.75 | 4,120 | 4.39 | 0.85 | 0.64 | | 4.42 | | 4.55 | 0.82 | 4.55 |
| Foyes Corner | 2 | Portsmouth | 34.5 | 12.47 | 7.5 | 4,170 | 4.45 | 1.69 | na | | 4.47 | | 4.60 | 1.63 | - |
| Goffstown | 27 | Bedford | 34.5 | 12.47 | 2.5 | 1,548 | 1.65 | 1.51 | na | | 1.66 | | 1.71 | 1.46 | - |
| Hancock | 95 | Newport | 34.5 | 12.47 | 6.25 | 1,220 | 1.30 | 4.80 | na | | 1.31 | | 1.35 | 4.64 | - |
| Hanover St. | 16W1 | Manchester | 34.5 | 12.47 | 3.75 | 2,830 | 3.02 | 1.24 | na | | 3.04 | | 3.12 | 1.20 | - |
| Hanover St. | 16W3 | Manchester | 34.5 | 12.47 | 3.5 | 3,200 | 3.41 | 1.03 | na | | 3.43 | | 3.53 | 0.99 | 3.53 |
| High St. | 8 | Derry | 34.5 | 12.47 | 5.25 | 432 | 0.46 | 11.40 | na | | 0.46 | | 0.48 | 11.02 | - |
| Hollis | 24W1 | Nashua | 34.5 | 12.47 | 3.75 | 2,664 | 2.84 | 1.32 | na | | 2.86 | | 2.94 | 1.28 | - |
| Jackson Hill | 124 | Portsmouth | 34.5 | 12.47 | 10.5 | 6,694 | 7.14 | 1.47 | na | | 7.18 | | 7.39 | 1.42 | - |
| Jericho Rd. | 25 | Berlin | 34.5 | 12.47 | 2.5 | 703 | 0.75 | 3.34 | na | | 0.75 | | 0.78 | 3.22 | - |
| Lafayette Rd. | 58 | Portsmouth | 34.5 | 12.47 | 3.75 | 3,660 | 3.90 | 0.96 | 0.15 | | 3.93 | | 4.04 | 0.93 | 4.04 |
| Lancaster | 59 | Lancaster | 34.5 | 12.47 | 3.75 | 3,510 | 3.74 | 1.00 | na | | 3.76 | | 3.87 | 0.97 | 3.87 |
| Laskey's Corner. | 57 | Rochester | 34.5 | 12.47 | 3.75 | 1,107 | 1.18 | 3.18 | na | 0.29 | 1.48 | | 1.52 | 2.47 | - |
| Littleworth Rd. | 38W2 | Rochester | 34.5 | 12.47 | 3.75 | 3,070 | 3.27 | 1.15 | na | 0.80 | 4.09 | | 4.21 | 0.89 | 4.21 |
| Littleworth Rd. | 38W1 | Rochester | 34.5 | 12.47 | 3.75 | 3,510 | 3.74 | 1.00 | na | 0.91 | 4.68 | | 4.81 | 0.78 | 4.81 |
| Lochmere | 2W1 | Tilton | 34.5 | 12.47 | 3.75 | 1,775 | 1.89 | 1.98 | na | | 1.90 | | 1.96 | 1.91 | - |
| Lochmere | 2W2 | Tilton | 34.5 | 12.47 | 3.75 | 2,992 | 3.19 | 1.18 | na | | 3.21 | | 3.30 | 1.14 | - |
| Long Hill | 40 | Nashua | 34.5 | 12.47 | 5.25 | 4,200 | 4.48 | 1.17 | na | 1.00 | 5.50 | | 5.66 | 0.93 | 5.66 |
| Loudon | 31W2 | Tilton | 34.5 | 12.47 | 2.5 | 2,210 | 2.36 | 1.06 | na | | 2.37 | | 2.44 | 1.03 | - |
| Loudon | 31W1 | Tilton | 34.5 | 12.47 | 3.75 | 2,870 | 3.06 | 1.23 | na | | 3.08 | | 3.17 | 1.18 | - |
| Lowell Rd. | 72 | Nashua | 34.5 | 12.47 | 3.75 | 2,700 | 2.88 | 1.30 | na | | 2.90 | | 2.98 | 1.26 | - |
| Malvern Street | 188 | Hooksett | 34.5 | 12.47 | 12.5 | 7,518 | 8.02 | 1.56 | na | | 8.06 | | 8.29 | 1.51 | - |
| Meetinghouse Rd. | 31 | Bedford | 34.5 | 12.47 | 5.25 | 4,110 | 4.38 | 1.20 | na | - | 4.41 | | 4.53 | 1.16 | - |
| Meetinghouse Rd. | 32 | Bedford | 34.5 | 12.47 | 5.25 | 4,970 | 5.30 | 0.99 | 0.05 | - | 5.33 | 0.50 | 5.98 | 0.88 | 5.98 |
| Merrimack | 5 | Bedford | 34.5 | 12.47 | 5.25 | 1,303 | 1.39 | 3.78 | na | - | 1.40 | | 1.44 | 3.65 | - |
| Messer St. | 68 | Tilton | 34.5 | 12.47 | 12.5 | 5,897 | 6.29 | 1.99 | na | - | 6.33 | | 6.51 | 1.92 | - |
| Messer St. | 70 | Tilton | 34.5 | 12.47 | 5.25 | 6,811 | 7.26 | 0.72 | 2.01 | | 7.31 | | 7.51 | 0.70 | 7.51 |
| Milford | 23W7 | Bedford | 34.5 | 12.47 | 3.75 | 2,016 | 2.15 | 1.74 | na | - | 2.16 | | 2.22 | 1.69 | - |
| New London | 92 | Newport | 34.5 | 12.47 | 6.25 | 2,018 | 2.15 | 2.90 | na | | 2.16 | | 2.23 | 2.81 | - |
| No. Rochester | 391 | Rochester | 34.5 | 12.47 | 5 | 1,733 | 1.85 | 2.71 | na | | 1.86 | | 1.91 | 2.62 | - |

| | Total system CP MW | Total Dis Subst CP (MW) | Dis. Sub. load (MW) |
|---|---|---|---|
| 2017 | 1,959 | 326.6 | 16.67% |

Ratio

| | |
|---|---|
| 23.54% | **Share of Dis Subst Peak Load in areas likely to require capacity expansion 2019-2023** |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. Rochester | 392 | Rochester | 34.5 | 12.47 | 3.75 | 1,785 | 1.90 | 1.97 | na | | 1.91 | | 1.97 | 1.90 | - |
| Northwood Narr. | 49 | Epping | 34.5 | 12.47 | 1.5 | 250 | 0.27 | 5.63 | na | | 0.27 | | 0.28 | 5.44 | - |
| Notre Dame | 131 | Manchester | 34.5 | 12.47 | 4.2 | 3,240 | 3.45 | 1.22 | na | | 3.48 | | 3.57 | 1.17 | - |
| Opechee Bay | 9 | Tilton | 34.5 | 12.47 | 2.8 | 2,023 | 2.16 | 1.30 | na | | 2.17 | | 2.23 | 1.25 | - |
| Opechee Bay | 10 | Tilton | 34.5 | 12.47 | 2.5 | 2,400 | 2.56 | 0.98 | 0.06 | | 2.57 | | 2.65 | 0.94 | 2.65 |
| Pinardville | 18 | Bedford | 34.5 | 12.47 | 12.5 | 8,875 | 9.46 | 1.32 | na | - | 9.52 | | 9.79 | 1.28 | - |
| Portland St. | 34W4 | Rochester | 34.5 | 12.47 | 5.25 | 2,890 | 3.08 | 1.70 | na | | 3.10 | | 3.19 | 1.65 | - |
| Portland St. | 34W3 | Rochester | 34.5 | 12.47 | 5.25 | 4,660 | 4.97 | 1.06 | na | | 5.00 | | 5.14 | 1.02 | - |
| Sanbornville | 73W1 | Rochester | 34.5 | 12.47 | 3.75 | 1,900 | 2.03 | 1.85 | na | | 2.04 | | 2.10 | 1.79 | - |
| Sanbornville | 73W2 | Rochester | 34.5 | 12.47 | 3.75 | 3,040 | 3.24 | 1.16 | na | | 3.26 | | 3.35 | 1.12 | - |
| Simon St. | 6 | Nashua | 34.5 | 12.47 | 3.75 | 2,960 | 3.16 | 1.19 | na | | 3.17 | | 3.27 | 1.15 | - |
| So. Manchester | 142 | Hooksett | 34.5 | 12.47 | 10.5 | 4,710 | 5.02 | 2.09 | na | | 5.05 | | 5.20 | 2.02 | - |
| So. Peterborough | 35 | Monadnock | 34.5 | 12.47 | 3.75 | 3,168 | 3.38 | 1.11 | na | - | 3.40 | 1.00 | 4.50 | 0.83 | 4.50 |
| Somersworth | 9 | Rochester | 34.5 | 12.47 | 8.4 | 2,210 | 2.36 | 3.56 | na | | 2.37 | | 2.44 | 3.45 | - |
| Suncook | 442 | Manchester | 34.5 | 12.47 | 3.75 | 4,370 | 4.66 | 0.80 | 0.91 | | 4.69 | | 4.82 | 0.78 | 4.82 |
| Valley Street | 94 | Hooksett | 34.5 | 12.47 | 12.5 | 7,417 | 7.91 | 1.58 | na | | 7.96 | | 8.18 | 1.53 | - |
| West Rye | 105 | Portsmouth | 34.5 | 12.47 | 12.5 | 6,250 | 6.66 | 1.88 | na | | 6.70 | | 6.90 | 1.81 | - |
| Whitefield | 1 | Lancaster | 34.5 | 12.47 | 3.75 | 2,190 | 2.33 | 1.61 | na | | 2.35 | 1.00 | 3.42 | 1.10 | - |
| Brook Street | 13TR1 | Hooksett | 34.5 | 13.8 | 10.5 | 1,963 | 2.09 | 5.02 | na | | 2.11 | | 2.17 | 4.85 | - |
| Brook Street | 13TR2 | Hooksett | 34.5 | 13.8 | 10.5 | 2,513 | 2.68 | 3.92 | na | | 2.70 | | 2.77 | 3.79 | - |
| | | | | | **476.9** | **274,298** | **292.46** | | **5.58** | **4.50** | **298.71** | **4.15** | **311.40** | **MW** | **75.77** |

WN 2017 factor: 1.066

Expected 2017-18 growth rate net of Ind. Load addit.: 0.60%

Expected 2018-2023 Growth net of step ind. load additions **2.86%**

2018-2023 growth

**4.25%** System-wide growth rate 2018-2023

2.86% Assumed cumulative growth from 2018-23 before known Industrial Load additions

**Peak Loads not using Bulk Station at NH (fed from Vermont)**

| | | | Pri kV | Sec kV | Nameplate | Year 2017 CP (kW) | 2017 Weather-Normalized MW | 2017 Capacity/ Load ratios | 2017 Shortage in constrained substations | 2018 assumed Ind. Additions | 2018 WN Peak Sub Loads | 2019 - 23 known ind. load additions | **2023 Peak Loads with ind. Load addit. (MW)** | 2023 Capacity/ Load Ratio | **2023 Capacity-constrained Load** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Byrd Ave (CVEC) | 60 | Newport | 46 | 12.47 | 14 | 6,500 | 6.93 | 2.02 | na | | 6.97 | | 7.17 | 1.95 | - | |
| River Road (CVEC) | 46 | Newport | 46 | 12.47 | 5.6 | 4,608 | 4.91 | 1.14 | na | - | 4.94 | 1.00 | 6.08 | 0.92 | 6.08 | |
| Spring Street (CVEC) | | Newport | 46 | 12.47 | 12.5 | 8,780 | 9.36 | 1.34 | na | | 9.42 | - | 9.69 | 1.29 | - | |
| Sugar River (CVEC | 54 | Newport | 46 | 12.47 | 12.5 | 6,050 | 6.45 | 1.94 | na | | 6.49 | - | 6.67 | 1.87 | - | |
| Sugar River (CVEC) | | Newport | 46 | 12.47 | 12.5 | 6,106 | 6.51 | 1.92 | na | | 6.55 | - | 6.74 | 1.86 | - | |
| | | | | | | 32,044 | 34 | | | - | 34 | 1.0 | **36.4** | | **6.08** | MW (fed from Vermont) |

**Public Service of New Hampshire d/b/a Eversource Energy**
**Docket No. DE 17-136**

**Date Request Received: 10/05/2018** **Date of Response: 10/19/2018**
**Request No. OCA 2-016** **Page 1 of 1**
**Request from: Office of Consumer Advocate**

**Witness: Katherine W. Peters, Eric Stanley, Mary Downes**

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**Request:**
Reference the EESE Board resolution of July 11, 2017 directing the utilities to "consider adding certain pilot projects to the Plan, e.g., geo-targeting," and to "review similar programs ongoing in other states to determine how the results of those pilot programs may inform efforts in New Hampshire." Have any of the joint utilities developed a cost-benefit model in the past year for a New Hampshire non-wire alternative project that included energy efficiency as one of the resources used to defer a distribution project? If so, please furnish that cost-benefit model in live excel format.

**Response:**
Eversource Response: No, Eversource has not developed a cost-benefit model as described in the past year. Eversource has not identified in the past year any viable non-wire alternative that incudes energy efficiency which could be used to defer a distribution project.

Liberty Response; Please see Liberty's response to OCA 1-11,b.

Unitil Response: Unitil has not created a cost benefit model for a New Hampshire non-wire alternative project used to defer a distribution project over the past year.

**Public Service of New Hampshire d/b/a Eversource Energy**
**Docket No. DE 17-136**

**Date Request Received: 10/09/2018** **Date of Response: 10/23/2018**
**Request No. CLF 2-014** **Page 1 of 1**
**Request from: Conservation Law Foundation**

**Witness: Katherine W. Peters, Eric Stanley, Thomas Palma**

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**Request:**
Please state whether each of the NH utilities has considered targeted energy efficiency as a non-wires/non-pipes alternative.

**Response:**
Yes, Eversource, Liberty, and Unitil consider targeted energy efficiency as non-wires/non-pipes alternatives as a part of their planning process.

Northeast Energy Efficiency Partnerships

# Energy Efficiency as a T&D Resource:

## Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments

January 9, 2015

Chris Neme & Jim Grevatt, Energy Futures Group

## About NEEP & the Regional EM&V Forum

NEEP was founded in 1996 as a non-profit whose mission is to serve the Northeast and Mid-Atlantic to accelerate energy efficiency in the building sector through public policy, program strategies and education. Our vision is that the region will fully embrace energy efficiency as a cornerstone of sustainable energy policy to help achieve a cleaner environment and a more reliable and affordable energy system.

The Regional Evaluation, Measurement and Verification Forum (EM&V Forum or Forum) is a project facilitated by Northeast Energy Efficiency Partnerships, Inc. (NEEP). The Forum's purpose is to provide a framework for the development and use of common and/or consistent protocols to measure, verify, track, and report energy efficiency and other demand resource savings, costs, and emission impacts to support the role and credibility of these resources in current and emerging energy and environmental policies and markets in the Northeast, New York, and the Mid-Atlantic region.

## About Energy Futures Group

EFG is a consulting firm that provides clients with specialized expertise on energy efficiency markets, programs and policies, with an emphasis on cutting-edge approaches. EFG has worked with a wide range of clients – consumer advocates, government agencies, environmental groups, other consultants and utilities – in more than 25 states and provinces.

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# Acknowledgements

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[1] See: http://www.neep.org/sites/default/files/EMV-Forum_Geotargeting_Subcommittee-List_12-5-14.pdf.

# I. Introduction

Improvements in the efficiency of energy use in homes and businesses can provide substantial benefits to the consumers who own, live in and work in the buildings. They can also reduce the need for capital investments in electric and gas utility systems – benefits that accrue to all consumers whether or not they participate in the efficiency programs. This report focuses on the role efficiency can play in deferring utility transmission and distribution (T&D) system investments. In particular, it addresses the role that intentional targeting of efficiency programs to specific constrained geographies – either by itself or in concert with demand response, distributed generation and/or other "non-wires alternatives" (NWAs)[2] – can play in deferring such investments. The report focuses primarily on electric T&D deferral, since that is where efforts in this area have focused to date. However, the concepts should be equally applicable to natural gas delivery infrastructure.

The report builds on a report published by the Regulatory Assistance Project (RAP) nearly three years ago.[3] Selected portions of the text of the RAP report – particularly for older case studies for which no update was necessary – have been re-used here. Several of the case studies highlighted in the RAP report have evolved considerably in the intervening years. There are also new case studies on which to report. This report documents these experiences and highlights some important new developments in the field that the recent experience has brought to light. In addition, to address the interests of the Regional EM&V Forum project funders, this report also includes an explicit set of policy recommendations or "guidelines".

The remainder of the report is organized as follows:

> **Section II: Efficiency as a T&D Resource** – summarizes the magnitude and drivers of T&D investment in the U.S., and provides an introduction to the concept of geo-targeting efficiency programs to defer some such investments.
>
> **Section III: Summaries of Examples** – provides high level summaries of about a dozen examples across the U.S. in which geographically targeted efficiency has been employed and/or is in the process of being employed, either alone or in combination with other NWAs, in order to defer more traditional T&D investments.

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[2] We use the term "non-wires alternatives" (NWAs) throughout this paper when referring to a range of alternatives to investment in the T&D system. That term is synonymous with "non-wires solutions", "non-transmission alternatives" (when referring to just the transmission portion of T&D), "grid reliability resources", "distributed energy resources", and other terms sometimes used by other parties. It should be noted that "non-wires" is an imperfect, "shorthand" term that is intended to refer to alternatives to a wide range of traditional T&D infrastructure investments, many of which – e.g. substations and/or transformers – are not really "wires".

[3] Neme, Chris and Rich Sedano, *"U.S. Experience with Efficiency as a Transmission and Distribution System Resource"*, Regulatory Assistance Project, February 2012.

**Section IV: Detailed Case Studies –** provides more detailed discussions of four of those examples which offer unique insights.

**Section V: Cross-Cutting Observations and Lessons Learned –** summarizes key conclusions the authors have drawn from the case studies examined in the report.

**Section VI: Policy Recommendations –** presents four policies that state governments should consider pursuing if they would like to effectively advance consideration of non-wires alternatives to traditional T&D investments.

**Section VII**: Bibliography – provides a list of all of the documents referenced in the report.

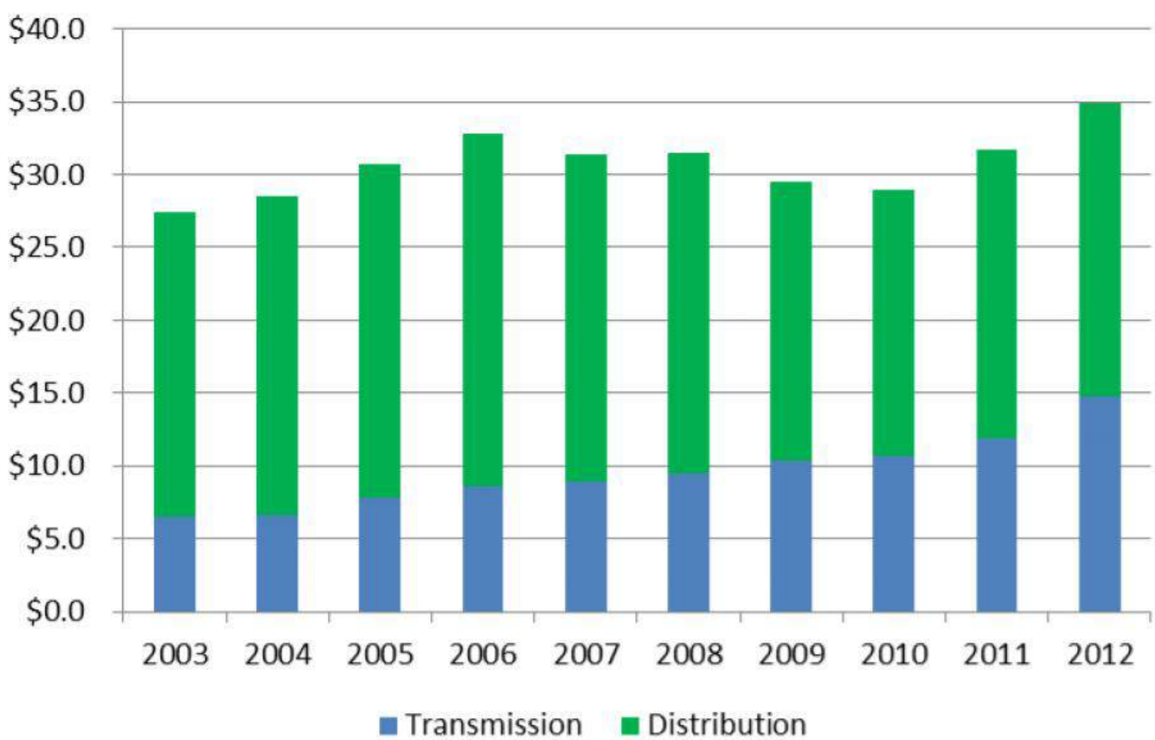
**Appendices –** contain excerpts from legislation in Vermont, Maine and California; regulatory standards for Rhode Island; and screening forms for Vermont that underpin those states' current requirements to consider and, where appropriate, promote non-wires alternatives.

# II. Energy Efficiency as a T&D Resource

## Context – Historic and Future Electric Utility T&D Investments

As Figure 1 shows, T&D investments by investor-owned electric utilities, which collectively account for approximately two-thirds of electricity sales in the U.S., have averaged a little more than $30 billion a year over the past decade. If public utilities[4] were investing at a comparable rate, total national investment would have been on the order of $45 billion per year.

**Figure 1: T&D Investment by U.S. Investor-Owned Utilities (Billions of 2012 Dollars)[5]**




That level of investment is expected to continue or increase in the future, with studies suggesting that the industry will spend an average of roughly $45 billion per year over the next two decades.[6,7] That would represent approximately 60% of forecasted utility capital investment.[8]

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[4] Public utilities include municipal utilities, rural electric cooperatives and the Tennessee Valley Authority.
[5] Edison Electric Institute, Statistical Yearbook of the Electric Power Industry 2012 Data, Table 9.1.
[6] Chupka, Marc et al. (The Brattle Group), *Transforming America's Power Industry: The Investment Challenge 2010-2030*, prepared for the Edison Foundation, November 2008. Harris Williams & Co., *Transmission and Distribution Infrastructure*, a Harris Williams & Co. White Paper, Summer 2014 (http://www.harriswilliams.com/sites/default/files/industry_reports/ep_td_white_paper_06_10_14_final.pdf?cm_mid=3575875&cm_crmid=e5418e44-29ef-e211-9e7f-00505695730e&cm_medium=email)
[7] Note that the ultimate cost to electric ratepayers may be significantly greater, since ratepayers will pay a rate of return on all investments made by regulated utilities.
[8] Chupka, Marc et al. (The Brattle Group), *Transforming America's Power Industry: The Investment Challenge 2010-2030*, prepared for the Edison Foundation, November 2008.

As discussed below, only a portion of T&D investment could potentially be deferred through deployment of energy efficiency and/or other non-wires alternatives. Data on the portion of U.S. T&D investment that might be deferrable are not currently available.

## When Efficiency Programs Can Affect T&D Investments

T&D investments are driven by a number of different factors. Among these are:

- The need to replace aging T&D infrastructure;
- The need to address unexpected equipment failures;
- The need to connect new generation – this is particularly important for renewable electric generation that is often sited in somewhat remote locations, but can also be true for other types of electric generation;
- A desire to provide access to more economic sources of energy and peak capacity; and
- The need to address load growth.

Needless to say, some of these needs would not be significantly affected by the customer investments in energy efficiency or the programs that promote such investments. In particular, investments related to the condition of a T&D asset – whether equipment has failed due to a defect or natural disaster or whether it is just too old and/or has become insufficiently reliable – are largely unaffected by the level of end use efficiency. In that context, it is worth noting that one of the reasons some are predicting national investment in electric T&D infrastructure to be substantial in the coming years is that much of the existing infrastructure is old. For example, it is estimated that approximately 70% of transformers are over 25 years old (relative to a useful life of 25 years), 60% of circuit breakers are over 30 years old (relative to a useful life of 20 years), 70% of transmission lines are 25 years old or older ("approaching the end of their useful life"), and more than 60% of distribution poles were installed 40 to 70 years ago (i.e. are approaching or have surpassed expected useful life of 50 years).[9] All told, the electric utility industry has estimated that between 35% and 48% of T&D assets either currently or will soon need to be replaced simply because of their age and/or condition.[10]

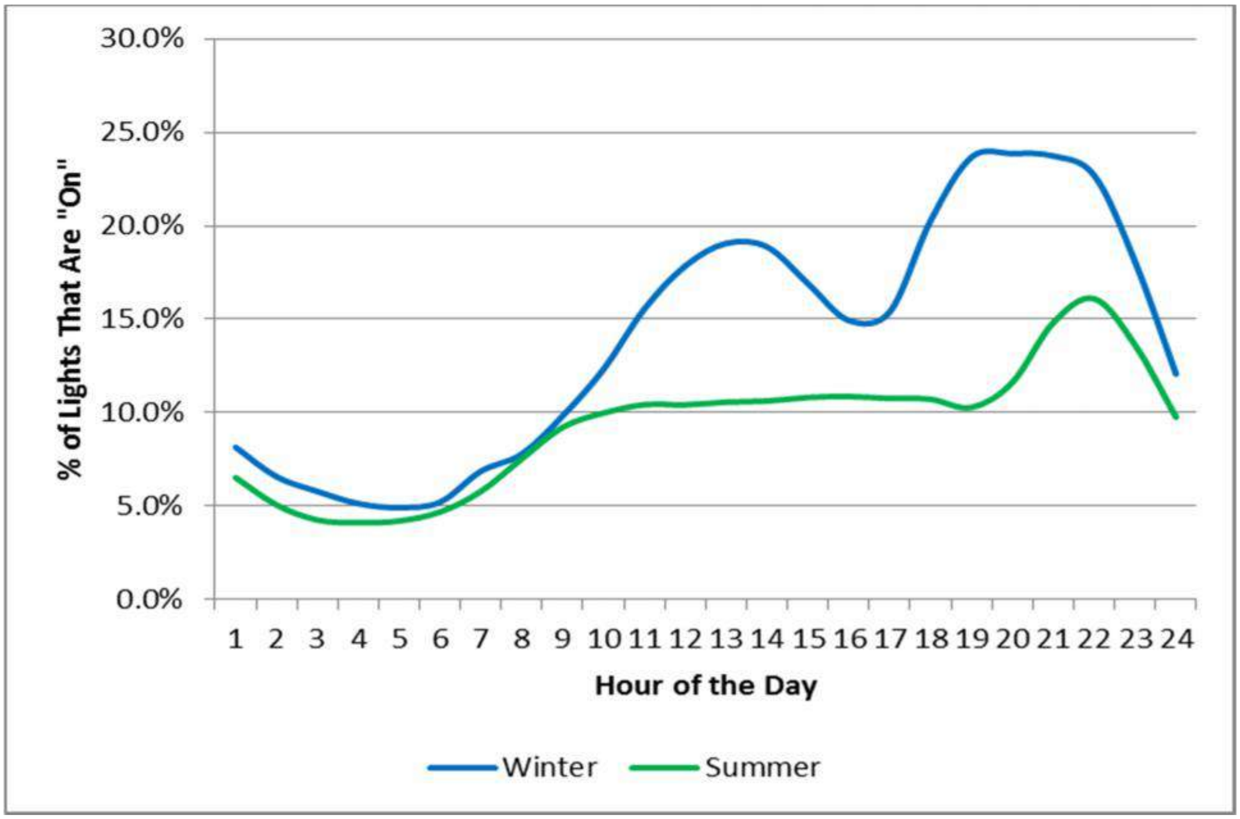
On the other hand, energy efficiency programs can defer T&D investments whose need is driven, at least in part, by economic conditions and/or growing peak loads. In that context, it is important to note that even if total electricity sales are not growing, peak load may be. Also, even if peak loads in a region are not growing *in aggregate*, they may be growing in a portion of the region to the point where they may be putting stress on the system.

[9] Harris Williams & Co., *Transmission and Distribution Infrastructure*, a Harris Williams & Co. White Paper, Summer 2014 (http://www.harriswilliams.com/sites/default/files/industry_reports/ep_td_white_paper_06_10_14_final.pdf?cm_mid=3575875&cm_crmid=e5418e44-29ef-e211-9e7f-00505695730e&cm_medium=email).
[10] Ibid.

## How Efficiency Programs Can Affect T&D Investments

Different elements of the T&D system can experience peak demand at different times of day and even in different seasons. Thus, the extent to which an efficiency program can help defer a T&D investment will depend on the hour and season of peak and the hourly and seasonal profile of the efficiency program's savings. For example, as shown in Figure 2, a program to promote the sale and purchase of compact fluorescent light bulbs (CFLs) provides some energy savings during every hour of the day (when sales are spread across many thousands of customers), but greater savings in winter than in summer and more savings in the evening than during the day.

**Figure 2: Average Hourly CFL Usage Patterns**[11]




Because different programs provide different levels of savings at different times and in different seasons, the *mix* of efficiency programs also matters. For example, as Table 1 illustrates, the same hypothetical mix of efficiency programs would have different impacts on three hypothetical electric substations which experience peak demands in different seasons and during different times of day because of the different mixes of customers that they serve. However, it is also worth noting that the differences across the portfolio of programs is not as great as across

[11] Nexus Market Research, *Residential Lighting Markdown Impact Evaluation*, submitted to Markdown and Buydown Program Sponsors in Connecticut, Massachusetts, Rhode Island and Vermont, January 20, 2009 (from Figures 5-1 and 5-2).

any individual program. This is the result of diversification, as the lower impact from one program is offset by a higher impact from another at the time of a given substation peak.

**Table 1: Hypothetical Efficiency Program Portfolio Impacts on Different Substation Peaks**

| | | | | Annual Peak MW Savings by Program | | | |
|---|---|---|---|---|---|---|---|
| Substation | Customer Mix | Peak Season | Peak Hour | Residential CFLs | Residential A/C | Commercial Lighting Retrofits | Total |
| A | Primarily Business | Summer | 3:00 PM | 0.4 | 0.9 | 0.7 | 2.0 |
| B | Primarily Residential | Summer | 7:00 PM | 0.4 | 1.4 | 0.3 | 2.1 |
| C | Primarily Residential w/Electric Heat | Winter | 7:00 PM | 1.0 | 0.0 | 0.4 | 1.4 |

Finally, the level of savings that the mix of programs provides also has important implications for whether any T&D investment deferral is possible and, if it is, how long a deferral the efficiency programs will provide. This is illustrated in the hypothetical example depicted in Table 2. In this example, the existing electric substation load is 90 MW and its maximum capacity is 100 MW, so capacity will need to be added by the year load is projected to exceed that level. The first scenario depicted is one in which there are no efficiency programs offered to customers served by the substation (i.e. a "business as usual" scenario). It assumes 3% annual growth in substation peak load. The other three scenarios depict different levels of efficiency program savings, presented in increments of 0.5 percentage point reductions in annual peak load growth relative to the "business as usual" or "no efficiency" scenario. In this example, the substation capacity would need to be upgraded in four years (2018) in the business as usual scenario. The degree to which the efficiency programs defer the need for the upgrade varies with the level of savings achieved, ranging from a one year deferral (to 2019) for savings sufficient to reduce the peak growth rate by 0.5% each year (i.e. from 3.0% to 2.5%) to an eight year deferral (to 2026) for savings sufficient to reduce the peak growth rate by 2.0% annually (i.e. from 3.0% to 1.0%). Clearly, if savings were greater than 2.0% per year, the need for the substation upgrade would be deferred beyond the time horizon depicted in the table.

**Table 2: Illustrative Impact of Savings Level (MW) on Deferral of Substation Upgrade**

| Level of Savings | Net Growth Rate | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No EE programs | 3.0% | 90 | 93 | 95 | 98 | 101 | 104 | 107 | 111 | 114 | 117 | 121 | 125 | 128 |
| 0.5% savings/year | 2.5% | 90 | 92 | 95 | 97 | 99 | 102 | 104 | 107 | 110 | 112 | 115 | 118 | 121 |
| 1.0% savings/year | 2.0% | 90 | 92 | 94 | 96 | 97 | 99 | 101 | 103 | 105 | 108 | 110 | 112 | 114 |
| 1.5% savings/year | 1.5% | 90 | 91 | 93 | 94 | 96 | 97 | 98 | 100 | 101 | 103 | 104 | 106 | 108 |
| 2.0% savings/year | 1.0% | 90 | 91 | 92 | 93 | 94 | 95 | 96 | 96 | 97 | 98 | 99 | 100 | 101 |

## Passive Deferrals vs. Active Deferrals

Energy efficiency programs can lead to deferrals of T&D investments in two ways: passive deferral and active deferral. We define those two concepts as follows:

> **Passive deferral**: when system-wide efficiency programs, implemented for broad-based economic and/or other reasons rather than with an intent to defer specific T&D projects, nevertheless produce enough impact to defer specific T&D investments.
>
> **Active deferral**: when geographically-targeted efforts to promote efficiency – *intentionally designed to defer specific T&D projects* – meet their objectives.

Passive deferrals, almost by definition, will occur to some degree in any jurisdiction that has system-wide efficiency programs of any significance. However, as noted above, the degree and value of passive deferral will obviously be heavily dependent on the scale and longevity of the programs. The benefits may be modest, deferring a small number of planned investments a year or two. They can be also quite substantial. For example, Consolidated Edison (Con Ed), the electric utility serving New York City and neighboring Westchester County, recently estimated that including the effects of its system-wide efficiency programs in its 10-year forecast reduced capital expenditures by more than $1 billion.[12] Similarly, since it began integrating long-term forecasts of energy efficiency savings into its transmission planning in 2012, the New England ISO has identified over $400 million in previously planned transmission investments in New Hampshire and Vermont that it is now deferring beyond its 10 year planning horizon.[13]

The benefits of such passive deferrals are sometimes reflected in average statewide or utility service territory-wide avoided T&D costs. Such avoided costs – along with avoided costs of energy and system peak capacity – are commonly used to assess whether efficiency programs are cost-effective (usually a regulatory requirement for funding approval). At the most general level,

[12] Gazze, Chris and Madlen Massarlian, "Planning for Efficiency: Forecasting the Geographic Distribution of Demand Reductions", in *Public Utilities Fortnightly*, August 2011, pp. 36-41.
[13] The initial March 2012 estimate was $265.4 million in deferred projects. In June 2013 an additional $157 million in projects was deferred (Personal communication from Eric Wilkinson, ISO New England, 11/6/14. Also see: George, Anne and Stephen J. Rourke (ISO New England), "ISO on Background: Energy Efficiency Forecast", December 12, 2012; and ISO New England, 2013 Regional System Plan, November 7, 2013).

estimates of avoided T&D costs are typically developed by dividing the portion of forecast T&D capital investments that are associated with load growth (i.e., excluding the portion that is associated with replacement due to time-related deterioration or other factors that are independent of load), by the forecast growth in system load. Such estimates can vary considerably, often as a function of the utilities' assumptions regarding how much investment is deferrable. For example, in New England, utility estimates of avoided T&D costs currently range from about $30 per kW-year (CL&P) to about $200 per kW-year (National Grid – Massachusetts).[14]

Like passive deferrals, the benefits of active deferrals are a function of the value of each year of deferral and the length of the deferral. However, because the deferral of a specific T&D investment is the primary objective rather than by-product of the efficiency programs, benefits are always very project-specific. Examples of such benefits are provided in the following sections of this report.

It is important to recognize that deferred T&D investments – whether passive or active – are a subset of the benefits of the efficiency programs that produced the deferral. Efficiency programs always also provide energy savings to participating customers, reductions in line losses, and environmental emission reductions. They also typically provide system peak capacity savings, reduced risk of exposure to fuel price volatility and, particularly in jurisdictions with competitive energy and/or capacity markets, price suppression benefits.

## Applicability to Natural Gas Infrastructure

Though this report focuses primarily on the role that efficiency programs can play in actively deferring *electric* T&D investments, the concepts are just as applicable to gas T&D infrastructure investments. That is, natural gas efficiency programs are likely to be passively deferring some gas T&D investments and, under the right circumstances – e.g. for load-related T&D needs, with enough lead time, etc. – should be viable options for deferring some gas T&D investments.

The passive deferral benefits of gas efficiency programs have either not been widely studied or not been widely publicized. However, there are at least a couple of examples worth noting. First, Vermont Gas Systems (VGS) routinely includes the impacts of its efficiency programs in its integrated resource planning (IRP). As noted in its revised 2012 IRP, efficiency programs are forecast to not only reduce gas purchases, but also contribute to "delayed transmission investment during the term of (the) plan."[15] In its 2001 plan, VGS was even more explicit, concluding that its efficiency programs would produce sufficient peak day savings to delay implementation of at least one transmission system looping project by one year.[16]

[14] Hornby, Rick et al. (Synapse Energy Economics), *Avoided Energy Supply Costs in New England: 2013 Report*, prepared for the Avoided Energy Supply Component (AESC) Study Group, July 12, 2013.
[15] Vermont Gas Systems, Inc., *REVISED Integrated Resource Plan*, 2012.
[16] Vermont Gas Systems, Inc., *Integrated Resource Plan*, 2001.

We are not aware of any publicly available documentation of examples in which a gas utility has used geographically-targeted efficiency programs to *actively defer* a T&D investment. However, there may be growing interest in this topic. For example, following a hotly contested proceeding on a very large gas pipeline project, the Ontario Energy Board recently concluded that geographically-targeted efficiency and demand response programs might have been able to mitigate the need for a portion of the project designed to meet growing loads in downtown Toronto, but "significant uncertainties", mostly related to time limitations and to Enbridge Gas' (the local gas utility's) lack of information on and experience with assessing peak demand impacts of its efficiency programs, led it to approve the project as proposed. However, the Board also stated that "further examination of integrated resource planning" is warranted and that it "expects applicants to provide more rigorous examination of demand side alternatives" in all future proposals for significant T&D investments.[17] In a very different context, some parties have suggested that geographic targeting of gas efficiency programs to areas near gas-fired electric generating stations could help alleviate pipeline congestion that is driving up the winter cost of electricity in parts of New England.[18] It is conceivable that such efforts might also help defer the need for some gas T&D investments.

NEEP will be undertaking a 2015 scoping project to document what gas system planners would need to assess the potential viability of demand-side alternatives to gas T&D investments.

[17] Ontario Energy Board, *Decision and Order*, EB-2012-0451, in the matter of an application by Enbridge Gas Distribution, Inc. Leave to Construct the GTA Project, January 30, 2014.
[18] Schlegel, Jeff, "Winter Energy Prices and Reliability: What Can EE Do to Help Mitigate the Causes and Effects on Customers", June 11, 2014.

## III. Summaries of Examples

Though far from widespread, a number of jurisdictions have tested and/or are in the process of testing the role that geographically-targeted efficiency programs could play in cost-effectively deferring electric T&D investments. In this section of the report we briefly summarize examples of such efforts from ten different jurisdictions. More detailed discussion of some of these examples follows in the next section.

### Bonneville Power Administration (under consideration in 2014)

The Bonneville Power Administration (BPA) has periodically considered energy efficiency and other non-wires alternatives to transmission projects over the past two decades. One notable example was in the early 1990s. At the time the Puget Sound area received more than three-quarters of its peak energy (i.e., during times of high demand for electric heat) via high voltage transmission lines that crossed the Cascade mountain range. BPA studies concluded the region could experience a voltage collapse – or blackout or brownout – if one of the lines failed during a cold snap.[19] The level of risk "violated transmission planning standards."[20] The traditional option for addressing this reliability concern would have been to build additional high voltage transmission lines over the Cascades into the Puget Sound area. However, BPA and the local utilities chose instead to pursue a lower cost path that included adding voltage support to the transmission system (e.g., "series capacitors to avoid building additional transmission corridors over the Cascades") and more intensive deployment of energy efficiency programs that focused on loads that would help avoid voltage collapse. The voltage support was by far the most important of these elements.[21] The project, known as the Puget Sound Area electric Reliability Plan, ended up delaying construction of expensive new high voltage transmission lines for at least a decade.[22] Indeed, no new cross-Cascade transmission lines have been built to date.[23]

Several years later, BPA invested in a substantial demand response initiative in the San Juan Islands to address reliability concerns after the newest of three underwater cables bringing power to the islands was accidentally severed. The initiative ran for five years and succeeded in keeping loads on the remaining cables at appropriate levels until a new cable was added.

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[19] U.S. Department of Energy, Bonneville Power Administration, Public Utility District Number 1 of Snohomish County, Puget Sound Power & Light, Seattle City Light and Tacoma City Light, "Puget Sound Reinforcement Project: Planning for Peak Power Needs", Scoping report, Part A, Summary of Public Comments, July 1990.

[20] Bonneville Power Administration Non-Construction Alternatives Roundtable, "Who Funds? Who Implements?" Subcommitee, "Non-Construction Alternatives – A Cost-Effective Way to Avoid, Defer or Reduce Transmission System Investments", March 2004.

[21] Indeed, though the plan included additional investments in efficiency, the additional capacitors, coupled with the addition of some local combustion turbines, were likely enough to defer the transmission lines even without the additional efficiency investments (personal communication with Frank Brown, BPA, 11/7/11).

[22] Bonneville Power Administration, "Non-Wires Solutions Questions & Answers" fact sheet.

[23] The system has been significantly altered over the past two decades as a result of substantial fuel-switching from electric heat to gas heat, the addition of significant wind generating capacity (much of it for sale to California) and other factors. Thus, today, BPA has more "North-South issues" than "East-West issues" (personal communication with Frank Brown, BPA, 11/7/11).

Although BPA has since commissioned several studies to assess non-wires alternatives to traditional transmission projects, it has not yet pursued any additional now-wires projects. BPA is currently in the process of rebooting and revamping their corporate approach to non-wires alternatives. That has included a restructuring of where this function is situated within the organization. Prior to 2012 the non-wires team at BPA was part of the Energy Efficiency team, but in early 2013 it became a corporate level function in an attempt to better integrate strategic planning for non-wires approaches across the organization by bridging the energy efficiency and resource planning functions.

BPA is also re-assessing the threshold criteria used to determine whether a project might be a good candidate for a non-wires approach. In the past, projects needed to be planned to be at least eight years in the future, and have a cost of at least $5M to be considered for a non-wires alternative. Currently the BPA team feels that an eight-year lead time is too long, because it allows too much time for projects to change in significant ways before they would be implemented. With this in mind they are now focusing on projects that are planned for five years out, feeling that this allows sufficient time to deploy non-wires resources while still providing greater surety that the project's expected need is reasonable. BPA has also reduced its minimum cost threshold from $5M to $3M.

The lead time and cost criteria are used as a "stage one" filter to identify potential NWA candidate projects. Once stage one selection is complete, a "stage two" analysis is undertaken. In stage two analysis BPA considers more specifically the types of customers in the affected load areas, and identifies the types of non-wires alternatives that could potentially be applicable and effective. Once this team has identified strong project candidates, recommendations are made to the executive team regarding projects to pursue. Once executive approval is obtained, the project would then move to a different branch of BPA for execution.

As in the Northeast there are significant unanswered questions about how future non-wires alternatives to transmission projects will be funded. Currently, transmission construction projects are socialized over a large customer base, but a similar cost-allocation mechanism has not yet been identified that would allow costs of non-wires alternatives to be similarly allocated. BPA is currently considering approaches to address this issue.

## California: PG&E (early 1990s pilot, new efforts in 2014)

One of the most widely publicized of the early T&D deferral projects was the Pacific Gas and Electric (PG&E) Model Energy Communities Program, commonly known as the "Delta project". The project ran from July 1991 through March 1993. Its purpose was to determine whether the need for a new substation that would otherwise be required to serve a growing "bedroom community" of 25,000 homes and 3000 businesses could be deferred through intensive efficiency investments. The largest portion of the project's savings was projected to come from a residential retrofit program targeted to homes with central air conditioning. Under the initial design, participating homes would receive free installation of low cost efficiency measures (e.g., CFLs, low flow showerheads, water heater blankets) during an initial site visit and be scheduled for follow up work with major measures such as duct sealing, air sealing, insulation, sun screening and air conditioner tune-ups. More than 2700 homes received such major measures. Later, the program changed its focus to promoting early replacement of older, inefficient central air conditioners with new efficient models. Other components of the Delta project included commercial building retrofits, a residential new construction program and a small commercial new construction program.

Evaluations suggested that the project produced 2.3 MW of peak demand savings. The savings did come at a higher cost than expected – roughly $3900 per kW. This can likely be attributed to a couple of key factors. First, the project had an extremely compressed timeframe. It was planned and launched within six months; the implementation phase was less than two years. A second related factor was that some of the efficiency strategies produced much lower levels of savings than initially estimated. Because of the compressed timeframe for the project, the switch in emphasis to the better performing program strategies could not occur early enough to keep total costs per kW at more reasonable levels. For example, the residential shell and duct repair efforts were initially projected to generate nearly 1.8 MW of peak demand savings but, in the end, produced only about 0.2 MW at a cost of over $16,000 per kW. In contrast, the early replacement residential central air conditioners produced 1.0 MW of peak savings – about 2.5 times the original forecast of about 0.4 MW – at a cost of about $900 per kW. The final evaluation of the project suggested that the savings achieved succeeded in deferring the need for the substation for at least two years.[24]

No other projects of this kind appear to have been pursued in California until very recently. Passage of Assembly Bill 327 in October 2013 required utilities to assess the locational benefits and costs of distributed resources (including efficiency), identify economically optimal locations for them, and put in place plans for their deployment. In response, PG&E started looking at specific capacity expansion projects at the distribution substation level that could be deferred if they could reduce load growth. The Company leveraged circuit-specific, 10-year, geo-spatial load forecasts[25] and identified roughly 150 distribution capacity expansion projects that would be needed over the next 5 years— and started developing criteria that would be useful in helping them select the potential deferral projects with the greatest likelihood of success. To narrow down the list, they focused on projects that:

- Were growth related rather than needed because of equipment maintenance issues;
- Had a projected in-service date at least 3 years into the future; and
- Had a projected normal operating deficiency of 2 MW or less at substation level to ensure that they would be realistically achievable in a two-year timeframe.

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[24] Pacific Gas and Electric Company Market Department, *"Evaluation Report: Model Energy Communities Program, Delta Project 1991-1994"*, July 1994.
[25] Using Integral Analytics proprietary "LoadSEER" software.

Applying these criteria reduced the number of projects being considered to about a dozen. PG&E then looked at each of the remaining projects more closely to better understand which customers were connected to those feeders and what their load profiles were like to determine if the needed reductions could be reasonably secured over the next two years. Through this process they ultimately selected four projects for which to deploy non-wires alternatives, including energy efficiency, for 2014-15. By the end of 2015 they expect to be able to show significant progress in developing their understanding of the strengths and potential limitations of these non-wires approaches, which will allow them to better integrate NWA approaches into future planning efforts. This current effort is discussed more thoroughly in the next section – detailed case studies – of this report.

## Maine (2012 to present)

In 2010, the Maine Public Utilities Commission approved a settlement agreement reached by Central Maine Power and a variety of other parties regarding a large transmission system upgrade project. A key condition of the settlement was that there would be a pilot project to test the efficacy of non-wires alternatives. The first such pilot was to be in the Boothbay region. Another condition was that the non-wires pilot would be administered by an independent third party. Grid Solar, an active participant in case, was selected to be the administrator.

The Boothbay pilot began in the Fall of 2012 with the release of an RFP designed to procure 2.0 MW of non-wires resources. Rather than solicit a purely least cost mix of resources, the project aimed to ensure that a mix of resource types would be procured and tested by establishing desired minimums of 250 kW for each of four different resource categories: energy efficiency, demand response, renewable distributed generation and non-renewable distributed generation. A second RFP was issued in late May of 2013 after one of the original winning bids withdrew due to challenges in acquiring financing. As of the Summer of 2014, 1.2 MW of non-wires resources, including approximately 350 kW of efficiency resources, were deployed and operational; another 500 kW was expected to be operational by late 2014. Due to revised load forecasts that total of 1.7 MW is all that is now expected to be needed to defer the transmission investment. The cumulative revenue requirement for the non-wires solution is now forecast to be approximately one-third of what the cost would have been for the transmission solution. This project, as well as recent legislation that requires assessment and deployment of less expensive non-wires solutions in the future, is discussed in greater detail in the next section of this report.

## Michigan: Indiana & Michigan/AEP (2014)

Indiana and Michigan (I&M), a subsidiary of American Electric Power (AEP), is currently forecasting that it will need to invest in an upgrade to a transformer at its substation in Niles, Michigan. The substation serves about 4400 residential customers, nearly 600 commercial customers and about 60 industrial customers. Peak load on the substation is currently 23.2 MW. It is forecast to grow by about 200 kW per year, though system planners need to address a possibility that peak loads will grow by 5% above normal weather levels – i.e. 210 kW per year.

I&M is currently considering a pilot project to use more aggressive efforts to promote energy efficiency investments to offset load growth and thereby defer the transformer upgrade. The efficiency program offerings would build on the system wide programs that are already offered across I&M's Michigan service territory, including both increased rebates for customers in Niles and more aggressive customer outreach and marketing efforts. There may also be efforts to explore integration of efficiency offerings with promotion of demand response and distributed generation.

## Nevada: NV Energy (late 2000s)

In 2008 NV Energy faced a situation in a relatively rural portion of its service territory, east of Carson City, in which growth in demand was going to need to be met by either running the locally situated but relatively expensive Fort Churchill generating station more frequently or constructing a 30 mile, 345 kVA transmission line and new substation to bring less expensive power from the more efficient Tracy generating facility (situated further north, about 20 miles east of Reno) to the region. When the local county commission began expressing concerns about permitting construction of the substation, regulators instructed the Company to increase the intensity of its DSM efforts in the targeted region as an alternative to meeting the area's needs economically:

> *"…the concentration of DSM energy efficiency measures in Carson City, Dayton, Carson Valley and South Tahoe has the potential to reduce the run time required for the Ft. Churchill generation units. The increased marketing costs and increased incentives and subsequent reduction in program energy savings required to attain an increased participation in the smaller market area are estimated to be more than offset by reduced fuel costs. Sierra Pacific, d.b.a. NV Energy, will make a reasonable effort within the approved DSM budget and programs to concentrate DSM activities in this area…"*[26]

NV Energy pursued a variety of efforts to focus its existing efficiency programs more intensely on the Fort Churchill area through increased marketing and, in one case (Commercial building retrofit program), higher financial incentives.[27] It also offered an "Energy Master Planning Service" to the Carson City and Douglas County School districts, though both declined the service. Of these efforts, NV Energy's second refrigerator collection and recycling program (including a new element of CFL distributions) and the commercial retrofit program were together responsible for the vast majority of the increased DSM savings in the region.[28]

At the same time as these efficiency efforts were launched, NV Energy's transmission staff began re-conductoring the existing 120 kVA line to the region to increase its carrying capacity. The economic recession also hit at the same time, dampening growth. As a result, the Company

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[26] Jarvis, Daniel et al., "*Targeting Constrained Regions: A Case Study of the Fort Churchill Generating Area*", 2010 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 178-189
[27] Sierra Pacific Power Company, 2010 Annual Demand Side Management Update Report, July 1, 2010, pp. 6-9.
[28] Ibid. and Jarvis et al.

has not had to revisit the need for either the additional power line and substation or increasing the run time of the Fort Churchill generating station. The project has also facilitated the beginnings of "rich conversations" between demand resource planners and transmission planners within the Company.[29]

## New York: Con Ed (2003 to present)

Consolidated Edison (Con Ed), the electric utility serving New York City and neighboring Westchester County, has been perhaps the most aggressive in the US in integrating end use energy efficiency into T&D planning. Geographically targeted investment in efficiency at Con Ed began in 2003, when growth in demand was causing a number of Con Ed's distribution networks to approach their peak capacity. In its initial pilot phase, the Company established contracts with three ESCOs to provide load reductions in nine networks areas: five in midtown Manhattan, three in Brooklyn and one in The Bronx. In subsequent phases, four different ESCOs were contracted to deliver load reductions in 21 additional network areas: 13 in Manhattan, four on Staten Island and four in Westchester County. ESCOs were allowed to bid virtually any kind of permanent load reduction. However, through 2010, the only cost-effective bids submitted and accepted were solely for the installation of efficiency measures. All told, between 2003 and 2010, the Company employed geographically targeted efficiency programs to defer T&D system upgrades in more than one third of its distribution networks. The resulting savings were very close to forecast needs and provided more than $300 million in net benefits to ratepayers.[30] In some cases, the efficiency investments not only deferred T&D upgrades, but bought enough time to allow the utility to refine load forecasts to the point where some of the capacity expansions may never be needed.

After these successful distribution deferral projects were completed in 2012, Con Ed experienced a brief hiatus from non-wires projects simply because there were no distribution upgrade projects being planned that would meet the criteria for non-wires approaches (see detailed case study in following section for discussion of these criteria). That changed in the summer of 2013, when an extended heat wave placed severe capacity pressure on areas of Brooklyn and Queens, causing Con Ed to identify a greatly accelerated need for upgrades to its system in these areas. Con Ed subsequently decided to request approval for approximately $200M in investments to defer distribution system upgrades related to these capacity constraints.

That proposal was also made in the context of strong signals coming from New York's regulators indicating a pending re-structuring of the electric utility industry in the state, with a much greater expectation that in the near future the utilities will be responsible for taking advantage of all available resources for managing the grid in the most economic manner. In

[29] Personal communication with Larry Holmes, NV Energy, 11/9/11.

[30] Gazze, Chris, Steven Mysholowsky, Rebecca Craft, and Bruce Appelbaum., "Con Edison's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction", in Proceedings of the ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 117-129; updated estimates provided by Chris Gazze, formerly of Con Ed, February 11, 2011.

Commission Staff's view, this includes deploying all manner of Distributed Energy Resources (DERs) to their cost-effective levels. This viewpoint is clearly reflected in ConEd's Brooklyn-Queens filing and the associated RFI that ConEd has issued that includes an extraordinary level of flexibility regarding the creative use of non-wires approaches. The Brooklyn-Queens project is discussed in much greater detail in the following "detailed case studies" section of this report.

## New York: Long Island Power Authority (2014)

PSEG Long Island[31] has submitted a proposed long-term plan to the Long Island Power Authority (LIPA) for its approval.[32] The plan includes initiatives designed to defer substantial transmission upgrades in the Far Rockaway region in southern Long Island and the South Fork region in eastern Long Island. Both include a proposed RFP to procure peak load relief, with any type of demand side measure – including energy efficiency – being eligible as long as it is commercially proven, is measurable and verifiable and is not duplicative of other programs already proposed for the areas.

In the case of the Far Rockaway region, the effort would be designed to help defer what would otherwise be a transmission reinforcement between the towns of East Garden City and Valley Stream in 2019. LIPA has already issued and received responses to an RFP for new generation, energy storage and demand response (GSDR) resources which may satisfy some or all of the need in the area. Thus, the proposed new RFP for demand-side resources is essentially a contingency plan. If deployed, it would seek to acquire 25 MW of "guaranteed capacity relief". PSEG Long Island has stated that the RFP process would be similar to Con Ed's process for addressing its Brooklyn-Queens constraint.

In the case of the South Fork region, the effort would be designed to help defer a $294 million capital investment in (primarily) new underground transmission cables and substation upgrades over the next eight years ($97 million by 2017 and the other $197 million through 2022). Approximately 20 MW of coincident peak capacity is needed by 2018, with more required in later years. It is expected that some of this need will be addressed by acquisition of storage resources through the GSDR RFP described above and 21.6 MW (nameplate capacity)[33] of solar PV procured through a different initiative. The RFP for demand side resources would seek at least 13 MW of guaranteed load relief, unless a parallel effort to acquire peak savings through a residential Direct Load Control program RFP acquires enough load control resources in the South Fork area to reduce the need.

[31] PSEG Long Island is currently contracted to provide all aspects of LIPA's utility services, other than procurement of supply resources. Starting in January 2015, it will also be responsible for supply procurement as well.
[32] PSEG Long Island, *"Utility 2.0 Long Range Plan Update Document"*, prepared for the Long Island Power Authority, October 6, 2014.
[33] That equates to more like 10 MW of coincident peak capacity and even less in early evening hours when demand in the region is still very high (personal communication with Michael Voltz, PSEG Long Island, November 13, 2014).

As of the writing of this report, these efforts are just proposals. They are expected to be considered for approval by the Long Island Power Authority Board in December 2014.[34]

## Oregon: Portland General Electric (early 1990s)

In 1992, Portland General Electric (PGE) began planning the launch of a pilot initiative to assess the potential for using DSM to cost-effectively defer distribution system upgrades; implementation began in early 1993.[35] The pilot focused on several opportunities for deferring both transformer upgrades planned for large commercial buildings and grid network system upgrades planned for downtown Portland, Oregon. The projects were identified from a review of PGE's five-year transmission and distribution plan. Though the PGE system was winter-peaking, downtown Portland was summer-peaking so the focus would be on efficiency measures that reduced cooling and other summer peak loads. To be successful, deferrals would need to be achieved in one to three years, with the lead time varying by project. In each case, the value of deferring the capital improvements was estimated. The estimates varied by area, but averaged about $35 per kW-year.[36]

Two different strategies were pursued. In the case of the individual commercial buildings, where peak demand reductions of several hundred kW per building were needed to defer transformer upgrades, the utility relied on existing system-wide DSM programs, but target marketed the programs to the owners of the buildings of interest using sales staff that already had relationships with the building owner or property management firm. For the grid network system objectives, where peak reductions of 10% to 20% for entire 10 to 15 block areas were needed, the utility contracted with ESCOs to deliver savings. The ESCO contracts had two-tier pricing structures designed to encourage comprehensive treatment of efficiency opportunities and deep levels of savings. The first tier addressed savings up to 20% of a building's electricity consumption. The second tier was a much higher price for savings beyond 20%.[37]

The results of the pilot were mixed. For example, savings in one of the targeted commercial buildings was nearly twice what was needed, deferring and possibly permanently eliminating the need for a $250,000 upgrade. However, savings for another building fell short of the amount of reduction needed to defer its transformer upgrade. While other options were being explored to bridge the gap, an unexpected conversion from gas to electric cooling of the building "eliminated any opportunity to defer the upgrade."[38]

The results for the first grid area network targeted were also very instructive. Of the 100 accounts in the area, the largest 20 accounted for more than three-quarters of the load. By

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[34] Personal communication with Michael Voltz, PSEG Long Island, November 11, 2014.
[35] Personal communication with Rick Weijo, Portland General Electric, August 10, 2011.
[36] Weijo, Richard O. and Linda Ecker (Portland General Electric), "Acquiring T&D Benefits from DSM: A Utility Case Study", Proceedings of 1994 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 2.
[37] Ibid.
[38] Ibid.

ultimately treating 12 of those 20, the ESCOs contracted by PGE actually succeeded in reducing load through efficiency measures by nearly 25% in just one year. That was substantially more than the 20% estimated to be necessary to defer the need for a distribution system upgrade. However, the utility's distribution engineering staff decided to proceed with construction of the upgrade before the magnitude of the achieved savings was known because they did not have sufficient confidence that the savings would be achieved and be reliable and persistent. It is also worth noting that the utility's marketing staff who were managing the ESCO's work were not even made aware of the decision to proceed with the construction until after it had begun – a telling indication of the lack of communication and trust between those responsible for energy efficiency initiatives and those responsible for distribution system planning.[39]

Despite some notable successes with its pilot, PGE has not subsequently pursued any additional efforts to defer distribution system upgrades through energy efficiency.[40]

## Rhode Island: National Grid (2012 to present)

In 2006, Rhode Island adopted a "System Reliability Procurement" policy that required utilities to file plans every three years. Guidelines detailing what to include in those plans were developed by the state's Energy Efficiency and Resource Management Council (EERMC) and National Grid and approved by regulators in 2011 (see Appendix D). The guidelines make clear that plans must consider non-wires alternatives, including energy efficiency, whenever a T&D need meets all of the following criteria:

- It is not based on asset condition;
- It would cost more than $1 million;
- It would require no more than a 20% reduction in peak load to defer; and
- It would not require investment in the "wires solution" to begin for at least 36 months.[41]

For such cases, the plans must include analysis of financial impacts, risks, the potential for synergistic benefits, and other aspects of both wires and non-wires alternatives.

Based on these guidelines, National Grid proposed an initial pilot project in late 2011. The project was designed to test whether geographically targeted energy efficiency and demand response could defer the need for a new substation feeder to serve 5200 customers (80% residential, the remainder small businesses) in the municipalities of Tiverton and Little Compton. The pilot began in 2012 with the objective of deferring the $2.9 million feeder project for at least four years (i.e. from an initial estimated need date of 2014 until at least 2018). The load

[39] Ibid.
[40] Personal communication with Rick Weijo, Portland General Electric, August 10, 2011.
[41] These criteria are identical to internal guidelines National Grid had developed in 2010/2011 (personal communication with Lindsay Foley, National Grid, December 22, 2014).

reduction necessary to permit the deferral was estimated to be 150 kW in 2014, rising to about 1000 kW in 2018.[42]

The pilot was designed to leverage National Grid's statewide efficiency programs in a couple of ways. First, the Company is more aggressively marketing those statewide programs to customers in Tiverton and Little Compton. Second, it is using the same vendor that manages its statewide residential and small commercial efficiency retrofit programs to promote demand response measures in the two towns. Because the substation's peak load is in the summer, there is a strong emphasis on addressing cooling loads. Initially, the demand response offering was a wi-fi programmable controllable thermostat for homes with central air conditioning. However, when the saturations of central air proved to be lower than expected, the pilot was broadened to include demand response-capable plug load control devices for window air conditioners. Marketing of the program offerings was limited to "direct contact" with customers in the affected towns. National Grid recently reported to state regulators that the need for the new feeder has been pushed out from 2014 to 2015, suggesting that the peak load reduction that has been realized thus far has been large enough to defer the investment by one year.[43]

## Vermont (mid-1990s pilot, statewide effort 2007 to present)

In 1995, Green Mountain Power (GMP), Vermont's second largest investor-owned electric utility at that time, launched an initiative – the first of its kind in the state – to defer the need for a new distribution line in the Mad River Valley – a region in the central part of the state made famous by the Sugarbush and Mad River ski resorts. Sugarbush, which was already the largest load on the line, had announced plans to add up to 15 MW of load associated with a new hotel, a new conference center and additional snow-making equipment. The existing line could not accommodate that kind of increase. Ensuing negotiations between GMP, Sugarbush and the state's ratepayer advocate ultimately led to an alternative solution in which Sugarbush would ensure that load on the distribution line – not just its load, but the total load of all customers – would not exceed the safe 30 MW level, and GMP would invest in an aggressive effort to promote investment in energy efficiency among all residential and business customers in the region. To meet its end of the bargain, GMP filed and regulators approved four efficiency programs targeted to the Mad River Valley, including a large commercial/industrial retrofit program, a small commercial/industrial retrofit program, a residential retrofit program that focused on homes with electric heat and hot water, and a residential new construction assessment fee program which imposed a mandatory fee on all new homes being constructed in the valley. The fee program paid for a home energy rating and offered both repayment of the fee and an additional incentive for building the home efficiently. The project as a whole came close to achieving its overall savings goal.

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[42] Anthony, Abigail (Environment Northeast) and Lindsay Foley (National Grid), "Energy Efficiency in Rhode Island's System Reliability Planning", 2014 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 10.
[43] Ibid.

Since that early project, Vermont has invested significant efforts in developing a thoughtful methodology for assessing the prudence of non-wired alternatives to capital investments in poles and wires. The Vermont Public Service Board (PSB) issued orders in Docket 7081 that established expectations for analysis of non-transmission alternatives, and in Docket 6290 for non-wires alternatives to distribution and sub-transmission projects. While the requirements vary slightly, similar approaches are used for both distribution and transmission needs. The state's distribution utilities and Vermont Electric Power Company (VELCO), the state's electric transmission provider, submit twenty-year forecasts of potential system constraints and construction projects as part of utility Integrated Resource Plans (IRPs) and a Long Range Transmission Plan (LRTP) every three years. The forecasts are updated annually. The forecasts include preliminary assessments of the applicability of non-wires alternatives based on criteria that have been agreed upon by Vermont System Planning Committee (VSPC), a statewide collaborative process for addressing electric grid reliability planning.[44] The VSPC helps Vermont fulfill an important public policy goal: to ensure that the most cost-effective solution gets chosen, whether it is a poles-and-wires upgrade, energy efficiency, demand response, generation, or a hybrid solution. The work of the VSPC is carried out by a broad cross section of stakeholders, including representatives from utilities, regulators, environmental advocates and Efficiency Vermont, and follows a highly prescribed process to assure that potential solutions are reviewed comprehensively.[45]

The current collaborative planning process was developed in response to Act 61, the 2005 legislation that clearly establishes the basis for the Public Service Board to require long range consideration of non-wires solutions as alternatives to T&D construction. Act 61 emerged in part as a result of public, regulatory, and legislative frustration with the Northwest Reliability Project, a transmission upgrade project that the Board ultimately felt it had to approve because, when permit applications were submitted there was no longer sufficient lead time to fairly consider NWAs. Act 61 also removed statutory spending caps for Efficiency Vermont, authorizing the Board to establish appropriate budgets. When the Board ordered budgets to increase beginning in 2007, it also required that a portion of the increase be devoted to special efforts to obtain additional savings in areas that the utilities had indicated had the potential to become constrained. Five geographic areas were initially targeted. At the time the Board required this geographic targeting effort primarily as a proof of concept, to assess Efficiency Vermont's ability to increase targeted savings while a better planning process was developed. Efficiency Vermont employed a number of program strategies in pursuit of their geographic goals, including enhanced account management approaches for commercial customers, a direct-install lighting program for small businesses, aggressive promotion of retail efficient lighting including community-based marketing approaches, and enhanced efforts to increase shell efficiency or fuel-switch electric heating customers. Vermont's process for evaluating the potential for non-

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[44] http://www.vermontspc.com/
[45] http://www.vermontspc.com/library/document/download/599/GTProcessMap_final2.pdf

wires solutions is discussed in much greater detail in the following “detailed case studies” section of this report.

# IV. Detailed Case Studies

## 1. Con Ed

### Early History with Non-Wires Alternatives

Con Ed arguably has more on the ground experience with using geographically targeted energy efficiency to defer or avoid T&D investments than any other utility in North America. This geographically targeted investment in efficiency began in 2003, when growth in demand was causing a number of Con Ed's distribution networks to approach their peak capacity. Given the density of its customer base in and around New York City, much of the company's system is underground, making upgrades expensive and disruptive. Thus, the Company began to assess whether it would be feasible and cost-effective to defer such upgrades through locally-targeted end use efficiency, distributed generation, fuel-switching and other demand-side investments. At least initially, the focus was on projects "with need dates that were up to five years out and…required load relief that totaled less than 3% to 4% of the predicted network load."[46] However, a decision was later made to proceed with geographically-targeted demand resource investments whenever it was determined that such investments were likely to be both feasible and cost-effective.

For these early projects, the Company chose to contract out the acquisition of demand resources to energy service companies (ESCOs). To address reliability risks its contracts contained both "significant upfront security and downstream liquidated damage provisions", as well as rigorous measurement and verification requirements, including 100% pre- and post-installation inspections. Contract prices were established through a competitive bidding process, with the Company's analysis of the economics of deferment being used to establish the highest price it would be willing to pay for demand resources. Those threshold prices varied from network to network. When the amount of demand resources bid at prices below the cost-effectiveness threshold were insufficient to defer T&D upgrades, supply-side improvements were pursued instead.

In its initial pilot phase, the Company established contracts with three ESCOs to provide load reductions in nine network areas: five in midtown Manhattan, three in Brooklyn and one in The Bronx. In subsequent phases, four different ESCOs were contracted to deliver load reductions in 21 additional network areas: 13 in Manhattan, four on Staten Island and four in Westchester County. Though ESCOs were allowed to bid virtually any kind of permanent load reduction, all of the accepted bids were solely for the installation of efficiency measures. All told, between 2003 and 2010, the Company employed geographically targeted efficiency programs to defer T&D system upgrades in more than one third of its distribution networks.

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[46] Gazze, Chris, Steven Mysholowsky, Rebecca Craft, and Bruce Appelbaum., "Con Edison's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction", in Proceedings of the ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 117-129.

This approach had considerable success. In aggregate the level of peak load reduction for Phase 1, which ran through 2007, was approximately 40 MW – or 7 MW less than the contracted level.[47] As a result, Con Ed collected considerable liquidated damages from participating ESCOs. Load reductions in subsequent phases were close to those contracted in aggregate. Those aggregate results masked some differences across network areas. In particular, reductions in areas dominated by residential loads with evening peaks were achieved ahead of schedule while "ESCOs targeting commercial customers in daytime peaking networks struggled somewhat due to the economic recession."[48] On the other hand, the economic recession also had the effect of dampening baseline demand, offsetting most of the efficiency program shortfalls.[49] This highlights an important benefit of some efficiency programs – their savings can be tied, in part, to the same factors (e.g. the vitality of the economy) that cause demand growth to rise or fall. Put another way, participation in some efficiency programs tends to increase when load is growing more quickly and decrease when load is not growing quickly.

Another benefit of efficiency programs is that they can create a hedge against load growth uncertainty. As Con Ed put it:

> *"…using DSM to defer projects bought time for demand uncertainty to resolve, leading to better capital decision making. Moreover, widespread policy and cultural shifts favoring energy efficiency may further defer some projects to the point where they are never needed…In fact, Con Edison has projected that in the absence of this program it would have installed up to $85 million in capacity extensions that may never be needed."*[50]

As Figure 3 shows, from 2003 to 2010, Con Ed estimated that it saved more than $75 million when comparing the full costs of its geographically targeted efficiency programs to just the T&D costs that were avoided. When other efficiency benefits (e.g., energy savings and system capacity savings) were also considered, the efficiency investments were estimated to have saved Con Ed and its customers more than $300 million. It should be noted that these estimates include the benefits of the longer-than expected deferrals and even outright elimination of the need for some T&D projects that resulted from the downside hedge against forecasting uncertainty described above. The benefits of just the planned deferrals – i.e. what would have been realized had the projects only been deferred as initially forecast – were lower.

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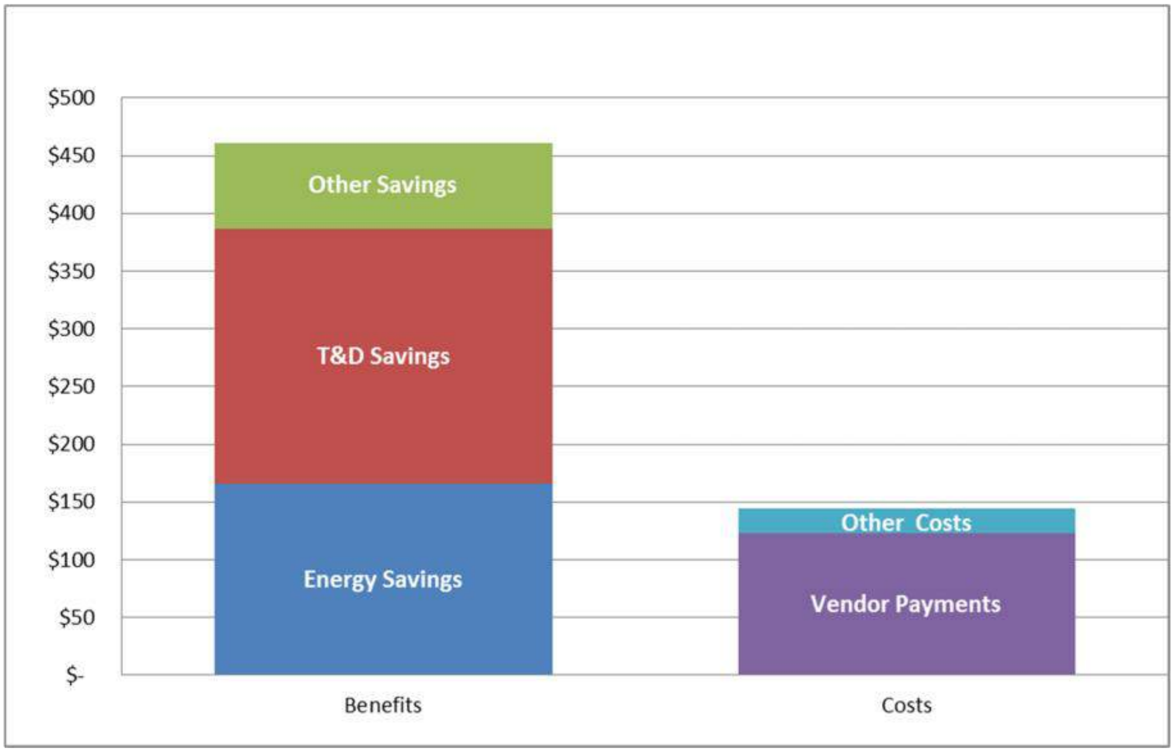
[47] Data obtained from graph in Gazze, Mysholowsky, Craft and Appelbaum (2010).
[48] Gazze, Mysholowsky, Craft and Appelbaum (2010).
[49] Gazze, Mysholowsky, Craft and Appelbaum (2010).
[50] Gazze, Chris et al., "Con Ed's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction", in Proceedings of the ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 117-129.

**Figure 3: NPV of Net Benefits of Con Ed's 2003-2010 Non-Wires Projects**[51]




## The Next Big Step - $200 Million Brooklyn-Queens Project

Building on this experience, in the summer of 2014 Con Ed requested regulatory approval to invest approximately $200M in a number of different approaches aimed at mitigating the immediate need for system reinforcement in areas of Brooklyn and Queens that surfaced during an extended heat wave in the summer of 2013 (see Figure 4).

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[51] Cost and benefit data provided by Chris Gazze, February 11, 2011. Note that "other costs" includes program administration ($2.9 million), M&V ($9.2 million) and customer costs ($9.9 million).

**Figure 4: Targeted Brooklyn-Queens Networks**[52]


Con Ed knew that there would be capacity constraints in these areas in the future, but the extreme weather placed severe capacity pressure on the sub-transmission feeders that feed the Brownsville No.1 and No.2 substations (serving areas of Brooklyn and Queens), causing Con Ed to identify a greatly accelerated need for upgrades to its system in these areas.[53] Rather than proceeding with a traditional construction solution, Con Ed's proposal calls for it to achieve 41 MW in customer side solutions and another 11 MW of capacity savings through "non-traditional utility side solutions" between 2016 and 2018. This will be combined with another 11 MW of load transfers and 6 MW from the installation of new capacitors that will be operational by 2016 to meet the increased demand during this period. To be clear, Con Ed views these measures as a deferral, rather than a replacement strategy, that will allow delaying the construction of a new substation and associated other improvements from 2017 until 2019. Future upgrades at two other substations are expected to extend this deferral until 2026.[54]

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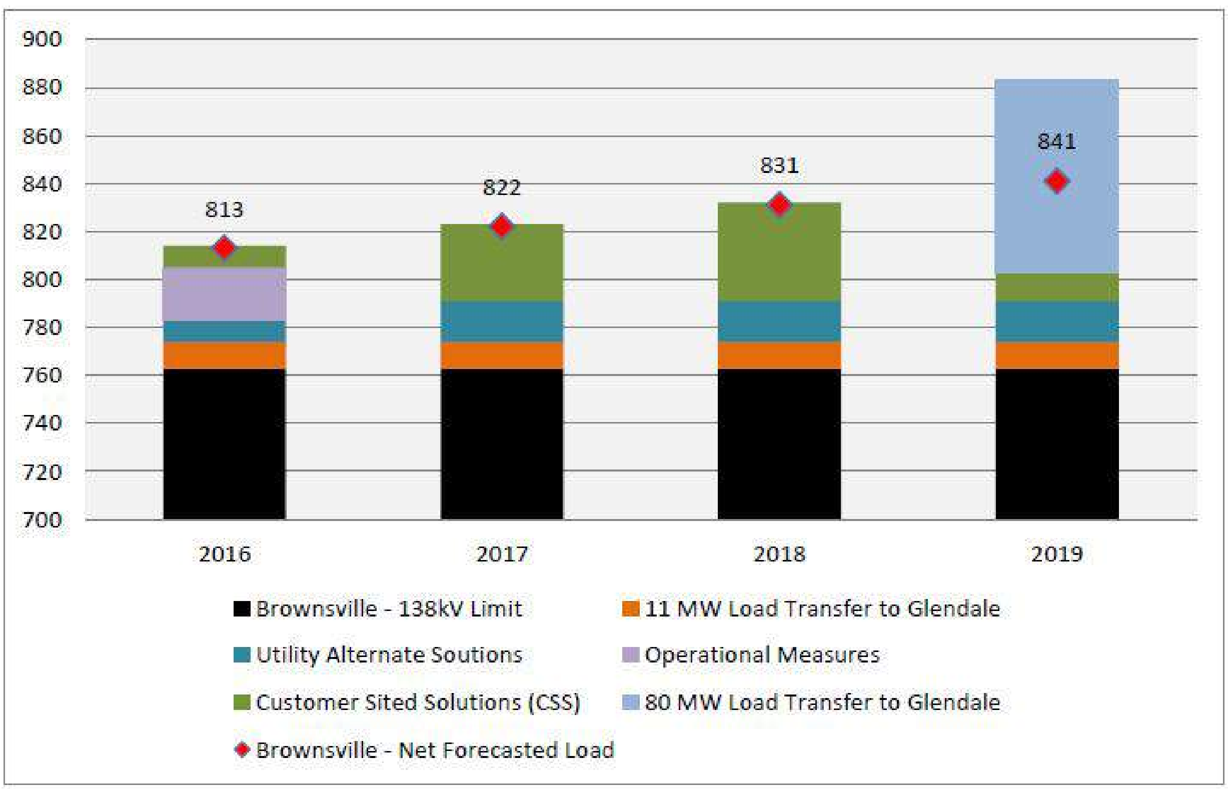
[52] Consolidated Edison Company of New York Request for Information, July 15, 2014, p.11.
[53] Personal communication with Michael Harrington of Con Ed, July 24, 2014.
[54] Data regarding Con Ed's proposal are from Consolidated Edison Company of New York, Inc. Brownsville Load Area Plan, Case 13-E-0030, August 21, 2014.
http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-e-0030, filing # 518

The overall expected project cost of the combination of the $200M in customer-side and utility-side investments, along with costs associated with the load transfers, new capacitors, and upgrades at the two other substations is not available in the documents reviewed in preparing this paper. However, Con Ed does say that the cost of the alternative purely "poles and wires" solution would be about $1 billion."[55] This traditional solution would include "…expansion of Gowanus 345kV switching station into a new 345/138kV step-down station…and…construction of an area substation and new sub-transmission feeders that would have been constructed and in service by the summer of 2017…."[56]

Figure 5 below illustrates the annual contribution of each component that combined will provide the needed load relief for the Brownsville Load Area in Brooklyn and Queens. Both traditional "poles and wires" solutions and non-traditional alternatives are needed to meet the anticipated load. The blue "utility alternate solutions" and the green "customer-sited solutions" together make up the NWAs for which Con Ed has sought approval.

**Figure 5: Brownsville Load Area Plan by Component: 2016-2019** [57]




55 Brownsville Load Area Plan, p.10
56 Brownsville Load Area Plan, p.10
57 Brownsville Load Area Plan, p.22

Con Ed's past success with implementing non-wires solutions gives it what is perhaps a unique, experience-based level of confidence in the effectiveness of alternatives to distribution construction. Likely of equal importance in Con Ed's decision to request approval for the Brooklyn-Queens project are the strong signals coming from New York's regulators, initially through feedback in a rate case[58] and later reinforced through proposals to re-structure the electric utility industry in New York. In particular, New York's Public Service Commission Staff have indicated that they foresee that in the near future the utilities will be held increasingly responsible for managing the grid in the most economic manner. In Commission Staff's view, outlined in *Reforming the Energy Vision* (REV),[59] this includes deploying all manner of cost-effective Distributed Energy Resources (DERs), in an environment where their benefits are accurately measured and given full attribution. The REV proceeding is currently underway in New York and the outcomes are undecided at the time of this writing, but clearly Con Ed has reflected anticipated changes in the regulatory framework in its Brooklyn-Queens filing, which will provide the most comprehensive test to date of the principles outlined in the REV.

Consistent with its regulatory filing, Con Ed issued an RFI in July of 2014 under the title "*Innovative Solutions to Provide Demand Side Management to Provide Transmission and Distribution System Load Relief and Reduce Generation Capacity Requirements*". The RFI allows for an extraordinary level of flexibility regarding the creative use of non-wires approaches:

> *"Respondents are encouraged to submit alternative, creative proposals for DSM marketing, sales, financing, implementation, and maintenance, or transaction structures and pricing formulas that will achieve the demand reductions sought and maximize value to Con Edison's customers."*[60]

While the Brooklyn-Queens project is receiving much attention for its unprecedented scale and ambition as a non-wires project, a concurrent evolution in several aspects of Con Ed's overall approach to non-wires alternatives may be even more important in the long run. Four recent developments are particularly noteworthy:

- **Management structure**: Con Ed's management of analysis and deployment of non-wires alternatives has been elevated to higher level in the Company and become more integrated/inter-disciplinary;
- **Data-driven tools**: Con Ed is developing data driven tools to enable much more sophisticated analysis of non-wires options; and

[58] Personal communication with Michael Harrington, Con Ed, December 9, 2014.
[59] NYS Department of Public Service Staff, *"Reforming the Energy Vision"*, Case 14-M-0101, 4/24/2014. http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/ATTK0J3L.pdf/Reforming%20The%20Energy%20Vision%20(REV)%20REPORT%204.25.%2014.pdf
[60] Consolidated Edison Company of New York Request for Information, July 15, 2014, p.6

- **Research to support tools**: Con Ed is investing in research to generate data necessary to support the use of those tools.
- **Proposed shareholder incentive mechanism**: Con Ed has proposed a new mechanism for enabling shareholders to profit from investment in non-wires alternatives.

## Evolution of Management Approach

Con Ed has taken significant steps in advancing internal communications and collaboration for the Brooklyn-Queens project that are expected to apply to other projects in the future. A working group has been formed within the company specific to this project that includes members of all relevant functional areas such as energy efficiency and demand management, distribution engineering, substation planning, electric operations, and the regional engineering groups that are responsible for Brooklyn/Queens. This has been done with the sponsorship, and under the guidance of one of Con Ed's Senior Vice-Presidents, who has championed the project and who regularly chaired early project meetings. Con Ed's senior management team regards the success of the Brooklyn-Queens project as highly important, and has brought organizational focus to it in a way that we did not observe in any of the other organizations we explored.[61]

## Development of New Data-Driven Analytical Tools

With a focus on system and cost management, along with the growth in efficiency and demand management technology and associated customer strategies, Con Ed identified the need for increased visibility into customer and technology potential and economics on the demand side. To address this need, Con Ed, along with Energy & Environmental Economics (E3) and Navigant, has created the Integrated Demand Side Management (IDSM) Potential Model – a dynamic, geographically specific, and technology integrated analysis tool to assess the market potential and economics of efficiency and demand management for cost effective deferral or avoidance of capital expenditures required to meet growing customer demand. The IDSM project is groundbreaking in its ability to breakdown the in-depth analysis into geographically specific electric networks to best match the needs of electric system planners.

The IDSM project goes beyond traditional efficiency measure stalwarts (lighting) to give Con Ed a view into potential deployments of all commercially available and near-term available technologies potentially applicable to the Con Ed service territory. The IDSM project will enhance Con Ed's ability to identify and market to high potential market segments to achieve efficient and effective capital project deferral projects. The model will also enable analysis of various DSM scenarios to customize and optimize project results and maximize cost effectiveness. Lastly, the IDSM project can be extended for use beyond TDSM project analysis

[61] Maine and Vermont have addressed the cross-functional nature of successful NWA planning and implementation through collaboratives that include members of different organizations, but we are not aware of an example other than Con Ed where this level of collaboration has occurred within a single utility.

to support Con Ed's strategic planning and resource planning (forecasting) efforts by identifying the market potentials and impacts for any number of customer technology adoption scenarios.

## Research to Support New Tools

Of course, analytical tools are only as good as the data put into them. Thus, Con Ed also embarked on a couple of research projects to support deployment of the IDSM.

In the first, Con Ed built up network profiles for eight test networks by collecting detailed granular customer data that accounts for building-level characteristics, and that are aggregated for up to 13 commercial and two residential segments for each electric network analyzed. Drawing from both internal billing data and external sources, the network profiles will include applicable service classes, meter information, annual and peak energy usage, air conditioning use, existing thermal storage, physical characteristics of the building, prior program participation, in-place DG/RE, end-use profiles, and more.

The second research task was a technology assessment to identify current and near-market technologies that have the potential to improve energy efficiency, support demand response, improve building operations, and maximize comfort. The assessment looked at the measures identified in a 2010 potential study, as well as additional technologies related at a minimum to lighting, controls, motors, HVAC, and thermal and battery storage. The project also looked at customer sited generation across a range of technology options.

In addition, the technology assessment included the develop of a measure specific load curve library by customer segment (e.g. 8760 and peak load curves for interior lighting measures for the retail customer segment) This tool connects the dots between the technology assessment and the network profiles to ensure the energy and demand reductions for measures being deployed for the specific customer segments are specific to the network(s) being analyzed. The tool does this by comparing the measure-segment load curves to the 8760 and peak load curves of the specific network. For example, the tool is able to assess the different impacts that residential lighting will have compared to commercial lighting in a night peaking network.

## Proposal for Shareholder Incentives

Con Ed has proposed to the Commission that it defer the bulk of the costs associated with customer-side activities and recover them over a five-year amortization period, and for utility-side expenditures it has proposed ten-year recovery. Con Ed suggest that "The shorter amortization periods than those traditionally afforded in rates reflect the nature of the expenditures…where no physical asset exists".[62] Con Ed suggests that it should earn a rate of

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[62] Consolidated Edison Company of New York, Inc., "*Petition for approval of Brooklyn/Queens Demand Management Program*", p.20. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bB2051869-3A4A-4A7D-BB24-D83835E2026F%7d

return equal to its overall approved rate of return, stating that "…ratemaking should make the Company indifferent to whether it invests in traditional or non-traditional solutions…."[63]

Further, Con Ed has proposed that the Commission establish up to a 100 basis point incentive on Brooklyn-Queens program investments that would be incremental to its approved rate of return so that it has a clear, direct interest in the success of the project. And lastly, the company has proposed that the Commission establish a shared savings incentive as well, with Con Ed earning 50% of the difference between the carrying costs of the traditional solution and the total annual collections for the Brooklyn-Queens program. As of this writing the Commission has not indicated how it will rule on these requests.

## 2. Maine (Boothbay) Pilot

### Project History and Plan

In 2008, Central Maine Power proposed a $1.5 billion investment in the Maine Power Reliability Program (MPRP) to modernize and upgrade the state's transmission network. The project was challenged, with one party – GridSolar – proposing instead that the state invest in 800 MW of photovoltaics (100 MW in the first five years) to offset the need for the entire MPRP. In June of 2010, the Maine Public Utilities Commission approved a settlement agreement reached by Central Maine Power (CMP) and a variety of other parties, including GridSolar and several public interest advocates.[64] The settlement supported construction of most elements of the MPRP, but identified two areas – the Mid-Coast region and the city of Portland – where pilot projects to test the efficacy of non-transmission alternatives would be launched. The Mid-Coast pilot was later reduced to a smaller pilot in the Boothbay region, roughly 35 miles ("as the crow flies") northeast of Portland (see Figure 6 below).

[63] Ibid., p.21.
[64] Maine Public Utilities Commission, Order Approving Stipulation, Docket No. 2008-255, June 10, 2010.

**Figure 6: Location of Maine (Boothbay) NTA Pilot**[65]


The Boothbay pilot was to be a hybrid solution. It included some transmission system investments, including rebuilding of the Newcastle 115 kV substation ($2.8 million), installing a second 2.7 MVAR capacitor bank at Boothbay Harbor 34.5 kV bus ($0.5 million, and 2.4 MVAR power factor correction at Boothbay Harbor 12 kV level.[66] In addition, the plan initially called for approximately 2 MW of non-transmission resources to be procured (in lieu of an $18 million investment in rebuilding of a 34.5 kV line).

The settlement agreement called for an independent third party to administer the acquisition and management of the non-transmission resources. GridSolar was contracted to serve as a third party administrator. Though the selection was not based on a competitive solicitation, the Maine Public Utilities Commission did formally ask if other parties would be interested and did not receive any other expressions of interest. In a docket that is currently open, the Commission is exploring, among other things, whether there should be an independent third party administrator for such projects in the future and, if so, how such parties would be selected (see discussion on next steps below).

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[65] Map copied from U.S. Department of Interior, U.S. Geological Survey, *The National Atlas of the United States of America*, www.nationalatlas.gov.

[66] Jason Rauch, Maine Public Utilities Commission, *"Maine NTA Processes and Policies"*, presentation to the Vermont System Planning Committee's NTA Workshop, October 11, 2013.

GridSolar used a competitive solicitation process to procure the non-transmission alternatives. The initial RFP was released in late September 2012. Because it was a pilot, it was decided that the Boothbay project would not solely be designed to acquire the least-cost non-wires solution for the area. Rather, it would also test the efficacy of a wide variety of alternative resource options. To that end, the RFP made clear that, to the extent feasible, GridSolar would endeavor to cost-effectively acquire (i.e. at a cost less than the transmission alternative) at least 250 kW of each of the following categories of resources:

- Energy efficiency;
- Demand response;
- Renewable distributed generation (at least half of which should be from solar PV); and
- Non-renewable distributed generation (with preference for those with no net greenhouse gas emissions).[67]

The RFP called for all bidding resources to be "on-line and commercially operable" by July 1, 2013 – just nine months after issuance of the RFP and less than six months after the expected date of contract signing – and committed to remain in service for a least three years. Contracts would guarantee payments for that three year period, with an option to extend payments for up to an additional seven years if approved by the Commission. Failure to meet the contractual deadline would result in a penalty of $2/kW-month.[68]

The RFP produced 12 bids from six different NTA providers totaling almost 4.5 MW. This included bids for efficiency, demand response, solar PV, back-up generators, and battery storage.[69] Nine of the bids were submitted for approval to the Commission. The nine bids would collectively have provided 1.98 MW spread across five different resource types – 156 kW of efficiency, 250 kWh of demand response, 338 kW of solar PV, 736 kW of back-up generators, and 500 kW of battery storage. During a January 2013 technical conference, GridSolar was given "preliminary approval" to negotiate contracts on those nine bids.[70]

In April 2013 GridSolar reported it had executed or was close to executing almost all of the contracts. The one key exception was a contract with one provider – Maine Micro Grid – who had bid all of the demand response and battery resources and a portion of the solar and back-up generator resources being recommended. While there was agreement on the contract terms, Maine Micro Grid was having difficulty securing financing for the project[71] and ultimately

[67] GridSolar, LLC, "*Request for Proposals to Provide Non-Transmission Alternatives for Pilot Project in Boothbay, Maine Electric Region*", September 27, 2012.
[68] Ibid.
[69] GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014.
[70] GridSolar, *"Implementation Plan & Final NTA Service Contracts"* (redacted version), for Docket no. 2011-138, April 5, 2013 (filed electronically on April 9, 2013.
[71] Ibid.

withdrew its bid, explaining that the limited contract commitment of three years was insufficient to satisfy investors "that the required 6-year holding period for the federal investment tax credit incentive would be satisfied."[72]

As a result, the Commission directed GridSolar to install a temporary back-up 500 kW diesel generator and issue a second RFP to fill the gap. The second RFP was issued on May 30, 2013. It produced 22 bids from ten different NTA providers totaling just over 4 MW. It too included bids for efficiency, demand response, solar PV, back-up generation and battery storage. The bid prices for all resources except energy efficiency went down in the second RFP. Even though the energy efficiency bid prices went up, efficiency resources remained by far the lowest cost resources (just by a smaller margin). After eliminating the most expensive bids, GridSolar recommended and received approval to proceed with putting in place contracts for the mix of resources summarized in Table 3. As discussed below, the final mix of NTAs contracted was slightly different from the mix shown in the table. The final contract prices were the same for the back-up generator (BUG) and demand response, but roughly $4 to $5 per kW-month higher for efficiency, solar PV and battery storage than the weighted three year prices shown in the table.[73]

**Table 3: Recommended NTA Resources[74]**

| | RFP I* | RFP II | Totals | Pct. | Units | Weighted 3 Year Price | Weighted 10 Yr. (Levelized) Price |
|---|---|---|---|---|---|---|---|
| Efficiency | 237.00 | 111.25 | 348.25 | 19% | 7 | $23.51 | $10.47 |
| Solar | 168.83 | 106.77 | 275.60 | 15% | 14 | $46.05 | $13.19 |
| BUG (same) | 500.00 | 500.00 | 500.00 | 27% | 1 | $17.42 | $20.63 |
| Demand Response | 0.00 | 250.00 | 250.00 | 13% | 1 | $110.00 | $57.65 |
| Battery | 0.00 | 500.00 | 500.00 | 27% | 1 | $163.70 | $75.99 |
| Total | 905.83 | 1468.02 | 1873.85 | | 24 | | |

* RFP I excludes Maine Micro Grid project; Efficiency increased to reflect EMT contract option.

As of July 2014, approximately 1203 kW of NTA resources were deployed and operational.[75] An additional 500 kW battery storage unit is currently expected to be operational by the end of 2014,[76] bringing the total operational capacity to 1703 kW.[77] That is nearly 300 kW less than the

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[72] GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014.
[73] GridSolar, *"Project Update: Boothbay Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, July 21, 2014.
[74] Table copied from GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014.
[75] GridSolar, *"Project Update: Boothbay Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, July 21, 2014.
[76] Personal communication with Dan Blais, GridSolar, October 14, 2014.
[77] Note that this value is about 170 kW less than shown in Table 3 above. That is because not all of the proposals initially approved for procurement were ultimately translated into contracts.

initially forecast need of 2.0 MW. However, in May 2014 Central Maine Power adjusted its forecast need for the 10-year planning horizon to be only 1.8 MW.[78] GridSolar had an option to acquire an additional 130 kW of efficiency resources from Efficiency Maine Trust. However, GridSolar, Commission Staff and other parties agreed not to pursue that option at that time, noting that it could be acquired later if necessary:

> *"A benefit of the NTA approach is that lump-investments and resource deployment can be more closely timed with need. To the extent that additional NTA resources are needed later to meet any increased load, they could be deployed at that time. The delay in investment saves ratepayers money."*[79]

## Energy Efficiency Strategy

As noted above, energy efficiency resources were a key component in the mix of NTA resources procured for the Boothbay pilot, accounting for approximately one-fifth of the total NTA capacity that has been procured.

All of the efficiency resources procured to date have been provided by the Efficiency Maine Trust (EMT), the independent third party administrator of efficiency programs in the state. Before responding to the first RFP, EMT contracted for a quick high level assessment of efficiency opportunities in the region. One of the findings was that there was significant lighting efficiency potential in local small businesses, including significant opportunities to displace very inefficient incandescent lighting. Given that opportunity – and the very tight timeline originally anticipated for producing savings (contracts to be signed in January 2013 with requirements for NTAs to be operational by July 1, 2013) – EMT focused its efforts almost entirely on lighting.

EMT employed two strategies for acquiring the savings. Most importantly, it ran what it called a "direct drop" program. That involved a bulk purchase of LEDs that could replace incandescent and halogen spotlights and direct delivery of the LEDs to businesses that indicated they would install them. At the time of the delivery, EMT also assessed opportunities for more expensive upgrades. However, because many of the businesses are seasonal (relying on the summer tourism trade), both profit margins and the potential cost savings from efficiency are often modest, making it difficult to persuade them to make any substantial investments. EMT also provided an "NTA bonus" on its standard business efficiency incentives for customers in the affected region. Several businesses, including a local grocery store, took advantage of that offer.

EMT had to be careful to explain why these offers were being made, so that it was clear why only customers in the region of interest were eligible. Nevertheless, there were still some customers from just outside the region that initially expressed annoyance that they could not take

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[78] Ibid.
[79] Ibid.

advantage of the NTA offers.  EMT had to follow up with those customers to clarify the purpose of the program and rationale for the geographic limitations of the special offers.

It should be noted that Efficiency Maine has indicated that "it could easily have secured much more efficiency had the design of the RFP permitted more flexible bid response and longer duration commitment."[80]

## Evaluation Strategy

The savings from efficiency measures in the project are estimated using the deemed values in EMT's Technical Reference Manual.  As required by the RFP, those values are consistent with the values accepted for peak savings by the New England ISO in its forward capacity market.

GridSolar conducted its first test of 472 kW of active NTA resources on July 1, 2014.  The BUG and demand response units were dispatched for an hour.  Based on data from the units themselves, as well as data from the affected substation circuits, it appears that the capacity of these resources was as predicted.

## Project Results

As noted above, to this point, the project appears to be performing as expected in terms of the magnitude of the resource being provided, though a key component for the future – battery storage – has not yet been tested.

With regards to cost, GridSolar has estimated that the project will be substantially less expensive than the transmission alternative.[81]  Indeed, as shown in Figure 7, it estimates that the revenue requirements for the pilot project will be $17.6 million lower – a more than 60% savings – over the project's potential 10-year life than under the full transmission solution.[82]  That is despite the intentional deployment of a range of NTAs that were not cost-optimized (so as to test a range of technology types in a pilot) and the fact that the pilot commitment to only three years of payments likely constrained potential bids.  Moreover, that cost comparison is not adjusted for the substantial additional benefits that some of the NTAs provide, such as energy savings during non-peak periods.

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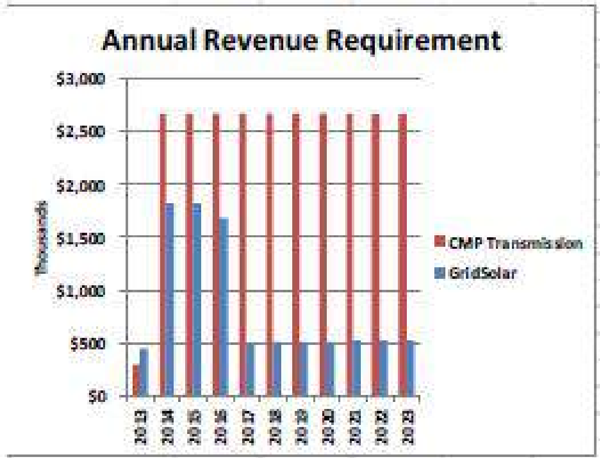
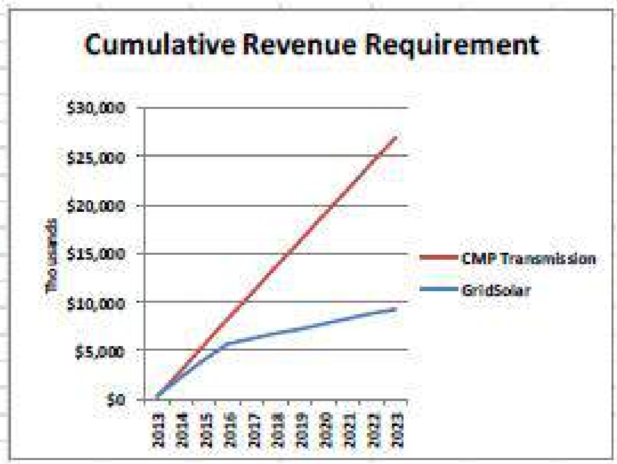
[80] GridSolar, "*Interim Report:  Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project*", for Docket No. 2011-138, March 4, 2014.

[81] As discussed above, there is a small transmission component to the pilot project.  When we refer to the transmission alternative here, we are referring just to the more substantial additional transmission investment that would have had to be made in the absence of the NTA deployments.

[82] Though this analysis only looks at a 10-year horizon, GridSolar expects that the pilot project will permanently eliminate the need for the transmission alternative (GridSolar, "*Interim Report:  Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project*", for Docket No. 2011-138, March 4, 2014 and personal communication with Dan Blais, GridSolar, October 14, 2014.

**Figure 7: Cost Comparison of Transmission and NTA Solutions for Boothbay**




One other important result worth re-stating about the project is that many of the passive resources, particularly energy efficiency, were among the first to be deployed. As GridSolar noted in its March 2014 project updates, this "bought time" for other NTAs to be brought on line:

> *"…To date, the Pilot has deployed over 400 kW of passive NTA resources…These passive resources alone exceed the projected grid reliability requirements in the Boothbay subregion…for the initial years of the Pilot…the subregion will not reach the projected critical loads in which the full suite of NTA resources are needed to meet reliability requirements in the out years of the Pilot project. This demonstrates the dynamic and modular nature of NTA solutions, which be ratcheted up or down year to year, as conditions require – thus lowering net costs and preventing premature or stranded costs due to overbuilding.*

Moreover, as noted above, the ability to quickly deploy some of the NTA resources bought time to allow for an updated peak forecast which lowered the magnitude of the total NTA required to meet reliability needs from 2.0 to 1.8 MW.

## The Future

In addition to continued implementation and evaluation of the Boothbay pilot, several other developments in Maine related to consideration of non-wires alternatives merit brief discussion.

First, and perhaps most importantly, the omnibus energy bill that became law in July 2013 contains important new language regarding consideration of NTAs. In particular, the bill requires the following:[83]

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[83] HP1128, LD1559, Item 1, 126th Maine State Legislature, "An Act to Reduce Energy Costs, Increase Energy Efficiency, Promote Electric System Reliability and Protect the Environment", Part C.

- No new transmission project of either (1) 69 kV or greater or (2) less than 69 kV with a project cost of at least $20 million can be built without consideration of NTAs;
- Assessment of NTAs must be performed by "an independent third party, which may be the commission or a contractor selected by the commission";
- The commission must "give preference" to NTAs when they are lower cost to ratepayers;
- When costs to ratepayers for a transmission project and NTAs are comparable, the commission must give preference to the option that produces the lowest air emissions (including greenhouse gases);
- If NTAs can address a need at lower total cost, but higher cost to ratepayers (because of socialization of the costs of transmission through ISO New England), the commission must "make reasonable efforts" to negotiate a cost-sharing agreement among the New England states that is similar to the cost-sharing treatment the transmission alternative would receive (the commission is given 180 days to negotiate such an agreement); and
- The commission is required to advocate "in all relevant venues" for similar treatment for analysis, planning and cost-sharing for NTAs and transmission alternatives.

The first NTA study required by the law is currently being undertaken in northern Maine (Docket 2014-00048). The Commission anticipates that two other potential Central Maine Power projects will trigger the study requirement.

Second, the Commission currently has an open docket in which it is considering whether to establish a permanent third party administrator of NTAs (initially Docket 2010-00267; now under Docket 2013-00519) and, if so, to establish how the administrator would be selected and overseen.[84] GridSolar has proposed that it become the state's coordinator. Other parties have some concerns. For example, Efficiency Maine Trust has expressed reservations about creating a new statewide third party administrator to manage consumer education, research and deployment of demand resources when it already plays that role for a subset of the resources (particularly energy efficiency and renewables). It has also expressed concern about inefficiencies in requiring it, as a regulated entity, to work through another regulated third party entity to get efficiency resources to be considered part of potential NTA solutions.[85] Instead, it suggests that cost-effective efficiency NTA resource be deployed in the future through the process EMT currently uses to make changes to its Triennial Plan.[86] GridSolar has itself recommended that in future projects efficiency resources should be procured "in partnership with EMT" and "outside the RFP process used to procure other NTA resources."[87]

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[84] Maine calls this position a "Smart Grid Coordinator", perhaps in part because the role may be larger than just managing NTAs.
[85] Personal communication with Ian Burnes, Efficiency Maine Trust, September 17, 2014.
[86] Mr. Ian Burnes and Dr. Anne Stephenson, Direct Testimony, Docket No. 2013-00519, August 28, 2014.
[87] GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014.

## 3. PG&E

### Legislative Requirements

PG&E, and presumably the other California electric utilities that are subject to the requirements of Assembly Bill 327 (AB 327), are in the early stages of identifying target areas that have rich potential for the deployment of non-wires alternatives. For PG&E, as these areas are identified, small pilot projects will be undertaken to test the potential for meeting growth-related needs through distributed resources rather than through construction of traditional poles and wires solutions. Signed by the Governor on October 7, 2013, AB 327 addresses several issues related to electric regulation and rates, and includes language laying out new expectations for resource planning, including the level of detail and rigor that utilities must apply. The law states that "Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources."[88] The Act further states that "…"distributed resources" means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response…." Sophisticated planning tools will be needed to meet the AB 327 requirement that these utilities must "Evaluate locational benefits and costs of distributed resources…." Until now, tools that can model distributed energy resources (DERs) have not been required.

### Selection of Pilot Projects

In response to these requirements, PG&E has begun working with several vendors to explore different tools and approaches for meeting the requirement for developing locational benefits and costs and for applying these values along with load and growth forecasts to develop an optimized distributed resources deployment plan. As an approach to testing the viability of this type of planning and deployment, PG&E began looking specifically at distribution substation level projects that potentially required attention due to load growth.[89] The Company ultimately identified approximately 150 capacity expansion projects that would need to be addressed in the next five years absent any action to defer them. They then applied criteria to identify projects that would be most suitable to explore for non-wires approaches. To make this cut, projects needed to:

- Be growth-related rather than related to any type of equipment maintenance issues;
- Have projected in-service dates at least three years out from the analysis date; and
- Have projected normal operating deficiencies of 2MW or less at the substation level.

These criteria were selected for this concept-testing period to identify projects that would have a strong chance for success. Applying these criteria whittled the list down significantly— to about

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[88] Section 769, California Assembly Bill 327
https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327

[89] At PG&E, distribution substations range typically serve between 5000 and 30,000 customers, with a total peak load of about between 20 MW and 100 MW (personal communication with Richard Aslin, PG&E, December 14, 2014).

a dozen remaining projects that had the potential to be candidates for NWAs. PG&E looked more closely at the connected loads and customer profiles for these remaining projects to get a more detailed sense of the types of NWAs that might be relevant in each project, and whether NWAs could realistically achieve the necessary load reductions. Through this process of careful selection, PG & E has identified four projects that it will use to test NWAs in 2014-15. By the end of 2015 they are confident that they will have a much better understanding of the opportunity to use NWAs to defer or avoid poles and wires construction projects.

## Efficiency Strategies

Given that these projects are still being developed for PG & E, there is not much actual experience to report on in terms of their approach to deploying energy efficiency in the four pilot areas. PG & E has a wide array of programs in its portfolio, so at present it is not planning to develop new program offerings for targeted areas. However, it is providing significantly larger incentives for custom C&I projects in targeted areas, and is working on making the non-trivial programming changes that will allow it to make corresponding changes for prescriptive measures. Making the programming changes that will allow tracking and reporting of different incentive levels in different areas is a critical step in developing the infrastructure that will allow successful use of DERs.

For residential customers, targeted measures include pool pumps and HVAC measures, with increased incentives available through the Upgrade California initiatives. PG&E is also doing an intense marketing campaign for its residential A/C cycling demand response program, and is offering increased incentives as well. To try to make sure that messaging is going to the right customers – to avoid the possibility that ineligible customers will want to take advantage of increased incentives – PG&E is primarily marketing the programs through installation contractors rather than using any kind of broad outreach campaign.

Outreach poses challenges related to making sure that the message gets to the right customers, but one of the additional challenges that PG&E has identified is the importance of getting the right message to customers in a way that won't cause them to worry about the lights going out. Many Californians remember rolling brownouts, and any hint that reliability is in question can evoke strong reactions. This may or may not be as much of an issue in jurisdictions that have no history of reliability issues.

## Addressing Management Challenges

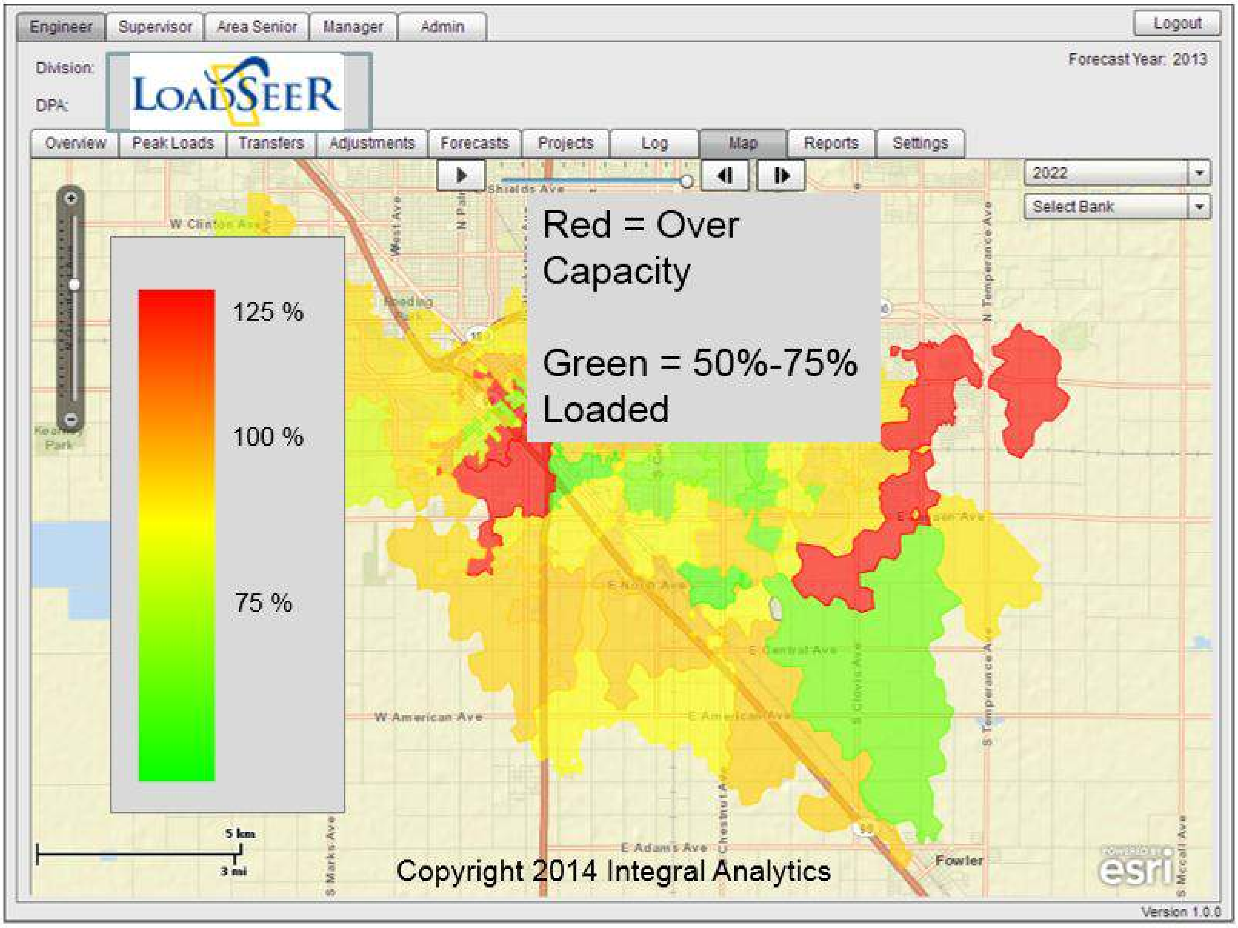
PG&E, like other utilities in this study, has identified challenges working across traditional utility organizational structures that typically have system planners operating in isolation from demand management and energy efficiency staff. PG&E, as well as other utilities with whom we talked, has found that system planners are often uncomfortable with the perceived level of uncertainty in non-wires solutions as compared with poles and wires solutions. Historically, the system planners' primary role is to provide certainty that the lights will stay on, and so the multifaceted complexity of non-wires solutions may seem less attractive than the alternatives with which they are more familiar.

PG&E staff are exploring organizational changes that might improve the cross-functional coordination of planning for alternatives to poles and wires. One of the steps that PG&E is undertaking to address planning integration between the two groups is – for the targeted substation projects – having dedicated customer energy solutions (CES) engineers and customer relationship managers work side-by-side with the distribution planning engineering teams. They are optimistic that through building these one-on-one relationships, and by having the engineers and customer relationship managers work "across the aisle", they will be able to provide the system planners with the level of assurance they require to more fully support potential NWAs.

## Use of New Data-Driven Analytical Tools

Moving forward, PG&E is likely to take greater advantage of sophisticated analytics and smart grid data to refine its analyses of the optimal locations for DER approaches. Currently it is working with a number of third party vendors and consultants to test the applicability of different data-driven approaches that will provide greater assurance to planners by better addressing the unknowns in the current planning process. One of these vendors, Integral Analytics, has already developed tools that will map and forecast loads and develop "distributed" marginal pricing (DMP) at the circuit or even customer level, with far greater precision than the locational marginal pricing (i.e. avoided costs) that are currently used to evaluate demand side management programs. These models not only map current loads, but also model loads out into the future, with the capacity to provide data-driven predictions of when loads will exceed a circuit's capacity to deliver it, as illustrated in Figure 8. DMPs will allow the development of avoided costs for specific, local areas, which will in turn allow precise analysis of the costs and benefits associated with DER projects. Moreover, the incorporation of power flow analytics below the substation can identify avoided costs that are not captured in traditional approaches (e.g. service transformer "reverse flow" risk from photovoltaics, voltage benefits, power factor value, primary vs. secondary losses, etc.) but which enhance the cost-effectiveness of most DERs, if located in the areas of higher avoided costs.

**Figure 8: Illustration of Integral Analytics LoadSEER Tool**




Consistent with anecdotal reports from several of the jurisdictions surveyed for this study, one of the primary benefits of considering NWAs is that refinements to the load forecasting and planning process, coupled with improved collaboration between demand-side and distribution engineering, results in planned capacity expansion projects being deferred for reasons beyond just the projected impacts of deployed DERs.

### Future Evaluation

As these pilots are just being developed at the time of this writing, there have not yet been any evaluations. However, PG&E will look very closely at the results of these pilots in the hope that DER approaches will become a much more prominent tool in its approach to reliably meeting its customers' energy needs.

## 4. Vermont

### Early History

As discussed above, Vermont successfully tested the application of non-wires alternatives in the Mad River Valley in the mid-1990s. A few years later, the state embarked on a path to establishing an independent "Efficiency Utility" – soon thereafter named Efficiency Vermont – that would be charged with delivering statewide efficiency programs. However, the order creating Efficiency Vermont made clear that the state's T&D utilities would still be responsible for funding and implementing any additional efficiency programs that could be justified as cost-effective alternatives to investment in T&D infrastructure (though they could contract implementation to Efficiency Vermont). The Vermont Public Service Board also agreed to "initiate a collaborative process to establish guidelines for distributed utility planning".[90] That collaborative culminated in a set of guidelines approved by the Board in 2003 in Docket 6290. Among other things, the distribution utilities were required to file integrated resource plans every three years. Those plans must identify system constraints that could potentially be addressed through non-wires alternatives.[91] The order also led to the creation of a number of "area specific collaboratives" in which opportunities for deferring specific T&D upgrades through non-wires alternatives would be explored by the utilities, the State's Department of Public Service and other parties. However, none of those discussions led to implementation of any such alternatives.

## Northwest Reliability Project

In 2003, VELCO,[92] the state's transmission utility, formally proposed a very controversial large project – the Northwest Reliability Project – to upgrade transmission lines from West Rutland to South Burlington. As required by Vermont law, VELCO filed an analysis of non-transmission alternatives. The analysis of a scenario including a combination of aggressive geographically targeted efficiency and distributed generation had a lower societal cost than the transmission line.[93] However, that option would involve much larger capital expenditures than the transmission line. Further, whereas much of the cost of the transmission option would be socialized across the New England Power Pool (Vermont pays a very small share of the portion of costs that are socialized across the region), the cost of the alternative path would be born entirely by Vermont ratepayers due to New England ISO rules. Those concerns, coupled with VELCO's concerns that the level of efficiency envisioned would be unprecedented, led the utility to argue in favor of the transmission option.[94] The Board ultimately approved VELCO's proposal in early 2005, but expressed concern and frustration with VELCO's planning process, namely that it did not consider alternatives, particularly efficiency, early enough in the process to make them truly viable options.[95]

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[90] Vermont Public Service Board Order, Docket No. 5980, pp. 54-58.
[91] Vermont Public Service Board Order, Docket No. 6290.
[92] VELCO is Vermont's electric transmission-only company, formed in 1956 to create a shared electric grid in Vermont that could increase access to hydro-power for the state's utilities. http://www.velco.com/about
[93] La Capra Associates, "Alternatives to VELCO's Northwest Reliability Project", January 29, 2003.
[94] Ibid.
[95] Vermont Public Service Board, "Board Approves Substantially Conditioned and Modified Transmission System Upgrade", press release, January 28, 2005.

## Act 61 – Institutionalizing Consideration of Non-Wires Alternatives

The approval of the transmission line contributed to the passage later that year of Act 61. Among other things, Act 61:

- required state officials to advocate for promotion of least cost solutions to T&D investments and equal treatment of the allocation of costs of both traditional T&D investments and non-wires alternatives "in negotiations and policy-making at the New England Independent System Operator, in proceedings before the Federal Energy Regulatory Commission, and in all other relevant venues…"
- required VELCO to regularly file a statewide transmission plan that looks forward at least 10 years; and
- eliminated the statutory spending cap for Efficiency Vermont, instructed the Board to determine the optimal level of efficiency spending, and made clear that cost-effectively deferring T&D upgrades should be one of the objectives the Board considers in establishing the budget.

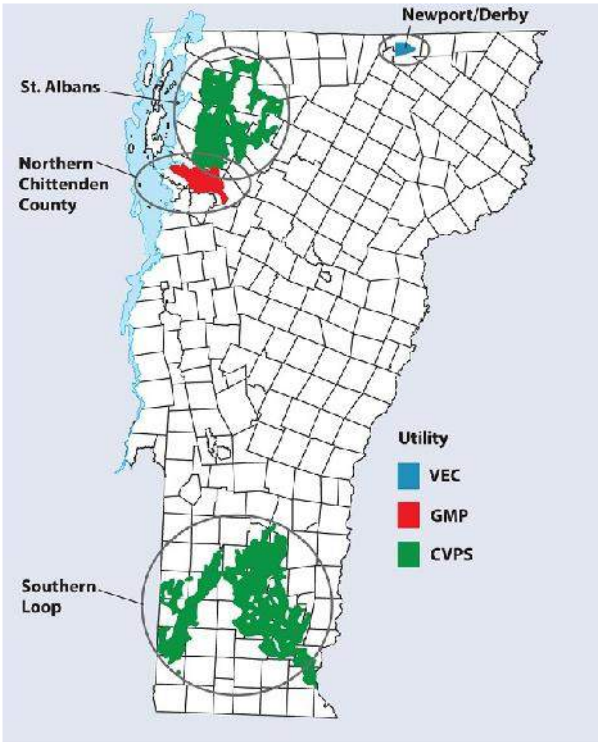
Key excerpts from Act 61 are provided in Appendix C.

## Efficiency Vermont's Initial Geo-Targeting Initiative

In response to passage of Act 61, the Public Service Board increased Efficiency Vermont's budget by about $6.5 million (37%) in 2007 and $12.2 million (66%) in 2008 and ordered that all of the additional spending be focused on four geographically-targeted areas: northern Chittenden County, Newport, St. Albans, and the "southern loop" (see Figure 9).[96] Those areas had been identified by the state's utilities as areas in which there may be potential for deferring significant T&D investment. Collectively, these efforts became known as Efficiency Vermont's initial "geo-targeting" initiative. [97]

[96] Vermont Public Service Board, *Order Re: Energy Efficiency Utility Budget for Calendar Years 2006, 2007 and 2008*, 8/2/2006.
[97] Efficiency Vermont Annual Plan, 2008-2009.

**Figure 9: Efficiency Vermont Geo-Targeting Regions (2007-2008)**




Efficiency Vermont was given peak savings goals for these areas that represented a 7- to 10-fold increase in the peak savings it had historically been achieving in the areas through its statewide efficiency programs. To meet the goals Efficiency Vermont initiated intensive account management of large commercial and industrial customers, launched a small commercial direct install program, and locally increased marketing and promotion of CFLs.

Approximately one year into its delivery, one of the four initially targeted areas (Newport) was dropped from the geo-targeting program when the distribution utility determined that the substation whose rebuilding the program was intended to defer needed to be rebuilt for reasons other than load growth (i.e., "destabilization of the substation property due to river flooding").[98] Independent of that decision, a new target area – Rutland – was added to the program beginning in 2009.

An evaluation of the 2007-2009 geo-targeting efforts suggested the results were mixed. On the one hand, program participation was two to four times higher in the geo-targeted areas than statewide. Savings per participant were also higher – 20-25% higher for business customers and 30% higher for residential customers. The net result was summer peak savings that were three to five times higher in the first couple of years than would have been achieved under the statewide

[98] Navigant Consulting et al., *"Process and Impact Evaluation of Efficiency Vermont's 2007-2009 Geotargeting Program"*, Final Report, Submitted to Vermont Department of Public Service, January 7.

programs.[99] On the other hand, those summer peak savings were still 30% lower than Efficiency Vermont's goals for the targeted areas; winter peak savings were 60% lower than goals. Nevertheless, analysis of loads on individual feeders in geo-targeted areas suggests that geo-targeting program impacts "are detectable at the system level" and that the magnitude of savings observed at the utility system level were consistent with those estimated through evaluation of customer savings.[100]

Evaluation of the impacts of the observed peak demand reductions on the potential deferral of T&D investments was not conducted. However, Central Vermont Public Service (the state's largest utility at the time)[101] has observed that it "has not been required to schedule the deployment of additional system upgrades in Rutland, St. Albans and Southern Loop areas". While it is difficult to know the extent to which that situation should be attributed to the geo-targeting of DSM, to changes in economic conditions (i.e., the recent economic recession) and/or to other factors, the Company did recommend to the Board that geo-targeting of DSM continue.[102] One Vermont official similarly noted that

### Vermont System Planning Committee

Subsequent to the passage of Act 61, the PSB initiated proceedings in Docket 7081 to develop a planning process that would ensure "full, fair and timely consideration of cost-effective non-transmission alternatives." The Public Service Board ultimately issued orders in 2007 approving an MOU between the major parties that established the Vermont System Planning Committee (VSPC) and charged it with carrying out this work.

The VSPC is a collaborative body. It brings together a wide range of viewpoints, including those of representative public stakeholders. There are six equally weighted voting contingents who are responsible for VSPC decisions on specific activities and projects:

- VELCO,
- large utilities with transmission,
- large utilities without transmission,
- other utilities without transmission,
- Efficiency Utilities (i.e. Efficiency Vermont and Burlington Electric Department) and renewable energy organizations, and
- public stakeholders.[103]

[99] Navigant Consulting et al., "Process and Impact Evaluation of Efficiency Vermont's 2007-2009 Geotargeting Program", Final Report, Submitted to Vermont Department of Public Service, January 7, 2011
[100] Navigant et al. (2011), p. 10.
[101] It was subsequently purchased and has become a part of Green Mountain Power.
[102] Silver, Morris, Counsel for Central Vermont Public Service, letter to the Vermont Public Service Board regarding "EEU Demand Resources Plan – Track C, Geotargeting", January 18, 2011.
[103] http://www.vermontspc.com/about/membership

The Public Service Board appoints the public stakeholders and the renewable energy representatives.

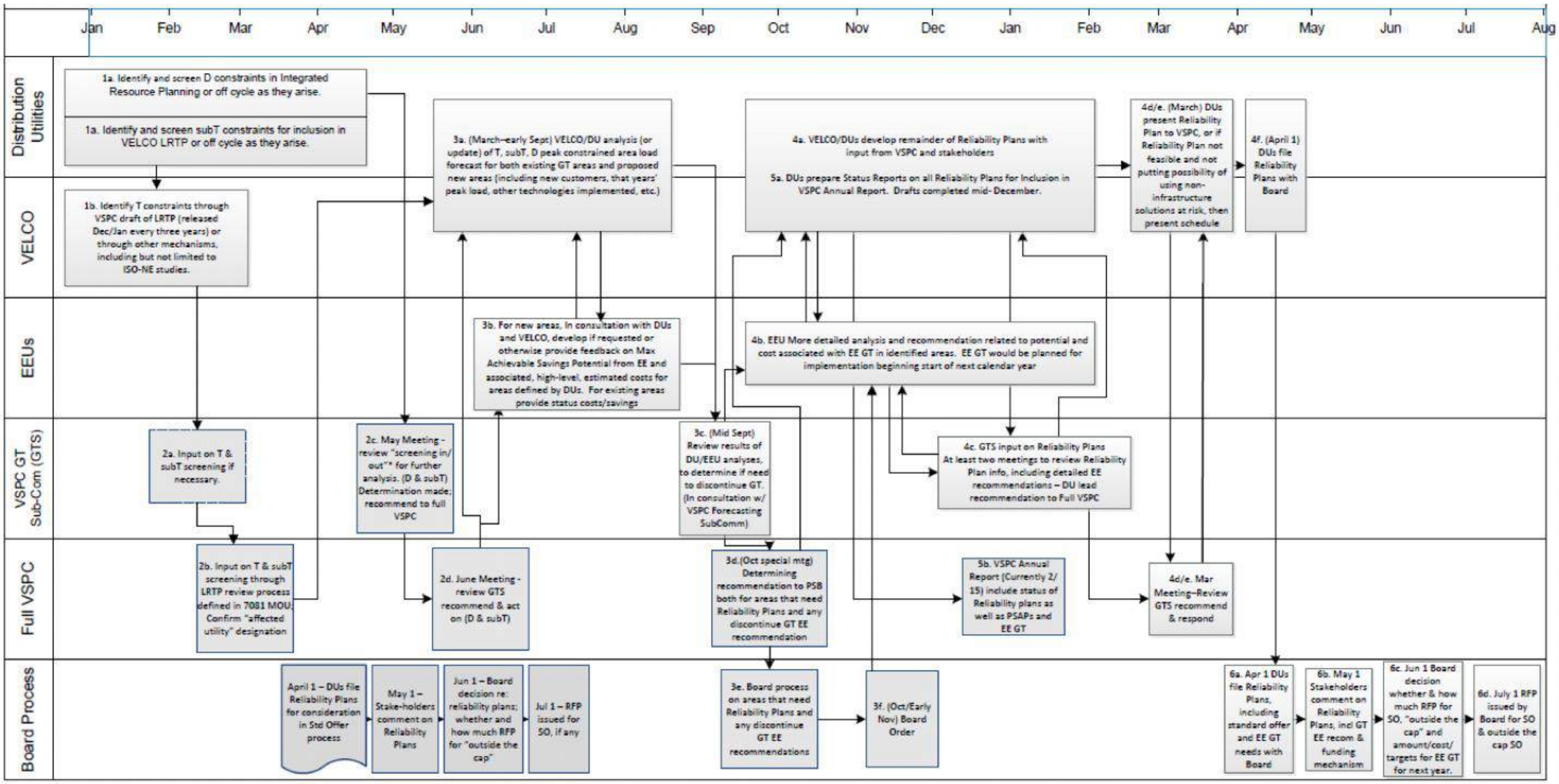
The VSPC process overcomes two significant barriers by first making sure that potential system constraints are identified as far in advance of their needed construction dates as possible, and secondly by ensuring that efficiency program planners are brought into the conversation early enough to determine whether efficiency is a viable alternative to construction given the particular customer segments that predominate in the targeted areas. Over time, the level of coordination in designing and implementing solutions has increased. In the first geographic targeting initiative undertaken by Efficiency Vermont in 2007, the state's utilities identified potentially constrained areas and then, with PSB approval, more-or-less handed the list to Efficiency Vermont. Now, with Efficiency Vermont serving as a fully participating member of the VSPC, a much more integrated approach is used, where the efficiency potential of constrained areas is investigated prior to their selection for geographically targeted efforts.

With the formation of the VSPC, significant efforts have also been invested in making sure that diverse viewpoints are represented in discussions regarding non-wires alternatives to both distribution and transmission construction. Further, a clear, well-documented and transparent process has been developed to make sure that results and decisions are firmly based on comprehensive consideration of evidence. This process has evolved over time. The current process is documented in Figure 10 below.[104]

In this process, VELCO, along with the large utilities that have transmission, is responsible for identifying bulk and predominantly bulk transmission system reliability improvement needs; the individual distribution utilities are responsible for identifying distribution and sub-transmission needs. Though they come from different dockets and legislation, in each case there is a requirement that these are identified on a three year basis, but project lists are also updated for the VSPC annually.

[104] http://www.vermontspc.com/library/document/download/599/GTProcessMap_final2.pdf

## Figure 10: Vermont Geo-Targeting Process Map (as of 9/11/2013)




*"Screening" refers to the use of the Docket 7081 screening tool for bulk and predominantly bulk transmission and the Docket 6290 screening tool for subtransmission and distribution issues to determine their potential to be resolved through energy efficiency and/or alternatives such as generation or demand response (or a hybrid of transmission with efficiency and/or generation). An issue is "screened in" if it has potential for a non-wires solution and therefore requires a Reliability Plan, and "screened out" if no potential is found and, therefore, no Reliability Plan is required.

**Key to abbreviations**

| | | | |
|---|---|---|---|
| D | distribution | LRTP | VELCO Long-Range Transmission Plan |
| DU | distribution utility | PSAP | project-specific action plan |
| EE | energy efficiency | RFP | request for proposal |
| EEU | energy efficiency utility | SO | standard offer |
| GT | geographic targeting | subT | subtransmission (subsystem) |
| GTS | VSPC Geotargeting Subcommittee | T | transmission (bulk/predominantly bulk) |
| | | VSPC | Vermont System Planning Committee |

As part of the development of T&D project lists, the utilities are required to use a set of "pre-screening" criteria to identify projects that might be candidates for non-wires alternatives. The key pre-screening criteria for distribution and sub-transmission projects are that the forecast "poles and wires" costs is greater than $250,000, that it is not required on an emergency basis, and that the need could be reduced by reductions in load.[105] For transmission projects to be considered for NWA approaches, the alternative needs to be projected to save at least $2.5M, needs to be able to be deferred or eliminated by a 25% or less reduction in load, does not need to be in place for at least one year into the future, and must not be needed for the purpose of meeting certain "stability" criteria related to grid performance. The VSPC reviews the utilities' initial project lists, including their pre-screening conclusions, and modifies them as appropriate. A recent example of a project list is provided in Table 4 below.

**Table 4: Green Mountain Power 2014 Forecast of Distribution System Needs**

| Constraint | Load Growth related (Y/N) | MW Need | Year of need | Zonal identified MW available (potential study) | Further screening (Y/N) |
|---|---|---|---|---|---|
| Susie Wilson Substation Area | Yes | | 2037 | | No Continue to Monitor |
| Wilder - White River Junction Area | Reliability and Load Growth | | 2015 | | No |
| Waterbury | Reliability | | 2015 | | No |
| Winooski 16Y3 Feeder | No | | 2015 | | No |
| Hinesburg | Yes | | 2016 | | No |
| Dover Haystack | Yes | | 2015 | | No |
| Stratton | Reliability | | 2015 | | No |
| St Albans | Reliability and Load Growth | | >10 years | | Reliability Plan filed 4/2/14, Continue to Monitor |
| Miton | Yes | | >10 years | | No Continue to Monitor |
| Brattleboro | Yes | | >10 years | | No Continue to Monitor |
| Southern Loop | Yes | | >10 years | | No Continue to Monitor |
| Danby | Reliability and Load Growth | | 2016 | | No |
| Granite-Whetmore | Asset Management | | 2016 | | No |
| South Brattleboro | Reliability | | 2016 | | No |
| 3309 Transmission | Reliability | | 2014 | | No Continue to Monitor / Refine the analysis |
| Rutland Area | Reliability | | Existing Constraint | | Reliability Plan filed 4/2/14, additional analysis required |
| Windsor Area | Reliability | | 2017 | | No |

For projects that pass the initial screen, the VSPC then follows the collaboratively-developed process to consider non-wires solutions, with the efficiency and renewables alternatives given a detailed look by Efficiency Vermont and other stakeholders. To date this analysis has been

[105] http://www.velco.com/uploads/vspc/documents/ntascreening_6290.pdf

conducted with only limited use of smart grid data. Efficiency Vermont has a deep knowledge of its customer base through nearly fifteen years of program implementation, and can also easily track prior efficiency improvements that targeted customers made through participation in Efficiency Vermont initiatives. While there is diversity among Vermont's commercial and industrial customers, they are still mostly relatively small compared to the C&I base in other jurisdictions, and so far Efficiency Vermont has been able to assess these opportunities without the use of more detailed analytic tools.

Efficiency Vermont's Strategy and Planning group has been responsible for identifying opportunities to increase efficiency in targeted areas and for designing program approaches to capture that efficiency. Generally, the implementation of any geographically targeted energy efficiency alternatives has been managed by Efficiency Vermont in a manner that is highly coordinated with its other state-wide efforts. Since beginning to implement geographically targeted initiatives in 2007 Efficiency Vermont has been cognizant of the need for sensitivity when it determines to only offer certain programs to some, rather than all customers. For this reason, they have decreased the use of special incentives in targeted areas in favor of increased outreach and communications. For example, the use of account management strategies for C&I customers is increased in geographically targeted areas, meaning that smaller customers who would not have received the attention of individualized account managers in non-targeted areas do receive that attention in targeted areas. This account management approach also allows Efficiency Vermont to focus on projects that have the potential to produce higher peak savings than average, thus increasing the ability of efficiency to defer construction compared to an "average" project that did not receive this level of guidance from account managers.

Efficiency Vermont has not done competitive solicitations to identify vendors who will commit to delivering certain savings through strategies of their own devising. Rather they have designed and managed program initiatives internally, with limited use of third-party vendors to implement programs for which Efficiency Vermont has developed the parameters. However they are investigating the potential to use the targeted deployment of third-party approaches in the future, specifically those that make use of smart grid data to identify savings opportunities to engage customers who might otherwise not have been aware of them.

With the VSPC process in place, the relationship between level of effort and the amount of resource needed in a specific area is much, much stronger. Where the first of Efficiency Vermont's geographically targeted efforts involved a single goal that could be met through savings in any of several targeted areas, goals are now set that are specific to each targeted area, and that reflect the actual need in that area as determined by system planners.

The VSPC and the planning process for non-wires alternatives have matured significantly in Vermont. Conversations with the Public Service Department and Efficiency Vermont both suggest confidence in the process. Going forward, it is expected that the VSPC process will continue to be used to identify potential candidates for geographic targeting of NWAs.

# V. Cross-Cutting Observations and Lessons Learned

Although the use of efficiency to meet T&D needs– either alone or in combination with other non-wires resources – is not yet widespread, it is fairly substantial and growing. That experience offers a number of insights, presented below, for jurisdictions considering the use of such resources in the future.

## The Big Picture

### 1. Geographically Targeted Efficiency Can Defer Some T&D Investments

Projects run by Con Ed (from 2003 through 2012), Vermont (both the initial Green Mountain Power Project in the mid-1990s and more recent examples), PG&E's Delta Project in California (in the early 1990s), and portions of PGE's project in downtown Portland, Oregon (also in the early 1990s), all demonstrably achieved enough savings to defer some T&D investments for at least some period of time. Preliminary results from the first year of experience with new projects in Maine and Rhode Island suggest that they too are likely on track to defer T&D investments.

### 2. T&D Deferrals Can be Very Cost-Effective

The cost-effectiveness of geographically-targeted efficiency programs and other non-wires resources will unquestionably be project-specific. That said, though data on the cost-effectiveness of T&D deferrals is not available for all of the projects we have examined, the information that is available suggests that efficiency and other non-wires resources can be very cost-effective – i.e. potentially much less expensive than "poles and wires" alternatives. For example, Con Ed's evaluation suggests that its geographically targeted efficiency investments from 2003 to 2010 produced roughly $3 in total benefits for every $1 in costs; the T&D benefits alone were worth 1½ times the costs of the programs. Similarly, the revenue requirements for Maine's pilot project are forecast to be more than 60% lower than for the alternative transmission solution.

### 3. There Is Significant Value to the "Modular" Nature of Efficiency and Other NWAs

One of the advantages of energy efficiency and other non-wires alternatives is that they are typically very modular in nature. That is, they are usually acquired in a number of small increments – e.g. thousands of different efficiency measures across hundreds, if not thousands of different customers, across several years. In contrast, the pursuit of a "poles and wires" strategy typically requires a commitment to much larger individual investments – if not a singular investment.

The modularity of efficiency and other non-wires alternatives allows for a ramp up or a ramp down of effort, either in response to market feedback (e.g. if customer uptake is greater or lower than expected) or in response to changing forecasts of T&D need. For example, as discussed in the case study of the Maine pilot project, the magnitude of the non-wires resource needed to defer the transmission investment has declined from an initial estimate of 2.0 MW to 1.8 MW.

Moreover, perhaps in anticipation of possible future changes, a decision has been made to not yet contract for the last 0.1 MW of need because that can be addressed at a future time if it is still determined to be needed. Similarly, again as noted above, Con Ed has found that one of the biggest advantages of its non-wires projects is that they have "bought time" for the utility to better tune its forecasts, to the point in a number of cases where the T&D investments once thought to be needed are now not anticipated to ever be needed.

### 4. Policy Mandates Are Driving Most Deployments of NWAs

Virtually all of the examples of the use of non-wires alternatives that we have profiled in this report were at least initially driven by either legislative mandates, regulatory guidelines or types of regulatory feedback. Examples of such requirements are provided in Appendices A through D.

The importance of policy mandates may be partly indicative of the nature of the internal barriers to utility pursuit of non-wires solutions. Utilities tend to be fairly conservative institutions. That is consistent with their primary mission of "keeping the lights on". It is understandable that they would be reluctant to change practices that they know are successful in serving that mission. As noted above, there are also challenges associated with persuading system planners that demand side alternatives can also be reliable.

In addition, utilities' financial incentives are generally not well aligned with the objective of pursuing cost-effective alternatives to "poles and wires". Right now, utilities can face a choice of earning money for shareholders if they pursue a traditional T&D path (because they earn a rate of return on such capital investments) or making no money if they choose to deploy non-wires alternatives.[106] To our knowledge, Con Ed's proposal for shareholder incentives for the large new Brooklyn-Queens project is the only proposal of its kind that attempts to directly address this issue.

## Implementation

### 5. Cross-Disciplinary Communication and Trust is Critical

This may seem self-evident, but it is critical nonetheless. T&D planners and engineers are often skeptical of the potential for end use efficiency and/or other demand resources to reliably substitute for poles, wires and other T&D "hardware". They worry that customers themselves are unreliable. Similarly, staff responsible for administration of programs that promote efficiency, load control, distributed generation or other demand resources typically do not fully

[106] Some utilities operate under capital spending caps. In such cases, the financial disincentives may be mitigated, at least in the short term, with money freed up from deployment of NWAs to defer or eliminate the need for some T&D investments effectively enabling the utility to invest in other T&D projects further down its priority list. However, if deployment of cost-effective NWAs is institutionalized, regulators could eventually respond by reducing capital spending caps.

understand the complexities of the reliability issues faced by T&D system planners. Both need to better understand the needs and capabilities of the other.

It can take time to develop the relationships and confidence necessary for efficiency program implementers and T&D system engineers to work together effectively. However, those relationships and that trust must be developed if efficiency programs are to successfully defer T&D investments.

Different jurisdictions and utilities have approached the challenge of facilitating cross-disciplinary collaboration differently. Con Ed has created a multi-disciplinary team that meets regularly under the direction of a Senior Vice President. PG&E has assigned field services engineers with customer-side experience to work side-by-side with distribution planning engineers on their pilot non-wires projects, with the expectation that the experience of working together will build trust and mutual understanding over time. Vermont's System Planning Committee serves a similar function, institutionalizing communication between system planners and those responsible for efficiency program delivery (as well as other stakeholders).

### 6. Senior Management Buy-in Is Invaluable

Senior management support for consideration of non-wires alternatives can be critical, if not essential, to facilitating the kind of cross-disciplinary collaboration that is necessary to be successful.

Senior management support will also be necessary to get to the point where consideration of cost-effective non-wires alternatives is routine and fully integrated into the way utilities run their businesses. As discussed further below, that, in turn, may require changes to utilities' financial incentives.

### 7. Smaller Is Easier

In general, all other things being equal, the smaller the size of the load reduction needed and the smaller the number of customers, the easier it is to plan and execute a non-wires solution. Smaller areas allow for greater understanding of both the customer mix and the savings or distributed generation opportunities associated with those customers. It is also generally easier to mobilize the existing demand resources delivery infrastructure (e.g. HVAC, lighting and/or other contractors) to meet a smaller need.

That is not to say that only small projects should be pursued, as the economic net benefits from larger projects also tend to be larger. Larger areas do offer one advantage: a more diverse range of customers and savings opportunities from which to choose in designing and implementing an NWA solution. A corollary to this point is that networked systems may be easier to address than radial systems because they allow for treatment of a larger number of customers to address a need. However, it is also important to recognize that larger projects with more customers over a larger geographic area will also be more complex and often require more lead time to plan and execute.

## 8. Distribution is Easier than Transmission

This may seem like just a corollary to the "smaller is easier", as distribution projects are generally smaller than transmission projects. However, there is more to it than that. For one thing, distribution system planning is generally less technically complex and more "linear" – 1 MW of load reduction commonly translates to 1 MW (adjusted for losses) of reduced distribution infrastructure need. In transmission planning 1 MW of load reduction in an area does not necessarily translate to 1 MW of reduced infrastructure need. In addition, distribution system planning typically involves fewer parties so decision-making is often more streamlined. Moreover, distribution reliability planning criteria can be less stringent than transmission planning criteria, so there may be opportunities to use NWAs with shorter time horizons and/or with less certainty that forecast savings will be achieved (i.e. there can be more flexibility for utilities in the timing of distribution infrastructure upgrades).

Finally, and perhaps most importantly, the cost allocations for both distribution system investments and their non-wires alternatives will typically both be fully and equally born by local ratepayers. This is in stark contrast to the allocation of transmission costs, which are governed by regional frameworks that inherently bias investments in favor of traditional "poles and wires" solutions. Typically transmission investment costs are socialized across multi-state regions, so that the state in which the transmission investment is needed pays only a portion of the project costs. In the case of non-wires alternatives, the state in which the project is deployed is made to bear all of the costs. Clearly, until this is addressed, it will continue to be challenging to implement NWAs to defer transmission projects.

## 9. Integrating Efficiency with Other Alternatives Will be Increasingly Common and Important

In several of the examples that we examined in this report geographically-targeted efficiency programs were enough, by themselves, to defer the traditional T&D investment. However, in some cases efficiency was effectively paired with demand response and/or other non-wires alternatives. As the projects being considered become larger and more complex and the development of non-wires solutions becomes more sophisticated, we expect such multi-pronged solutions to become more common. That is certainly the case, for example, with Con Ed's new Brooklyn-Queens project. Moreover, even a comprehensive suite of NWAs may be inadequate, by themselves, to address reliability concerns. In such cases, NWAs could potentially be paired with some T&D modifications, deferring only a portion of a larger T&D investment project.

## 10. "Big Data" and New Analytical Tools Enable More Sophisticated Strategies

Several of the geographic targeting projects that have occurred to date have found that the availability of savings was different from their initial expectations because their assumptions about the customers in the targeted areas were found to have been inaccurate. This was true for the Tiverton project in Rhode Island, where initial plans called for a substantial amount of demand response for residential central air conditioning systems, but where it turned out that the penetration of central air conditioning was much lower than originally expected. Similarly, Con Ed found that contractors weren't able to meet their savings targets in the later years of their initial geo-targeting efforts and attributed this to the lack of a detailed understanding of the types of customers and predominant end uses in the targeted areas.

Utilities have also faced uncertainty in assessing the cost-effectiveness of NWAs, in no small part because accurately assessing loads and growth is challenging, and utility system planners—who are responsible for assuring that the lights will stay on— may have some understandable bias towards high safety margins when assessing system capacity. Put another way, accurately valuing the economic benefits of alternatives to poles and wires approaches is not easy.

Reliable and malleable planning tools are needed that will allow more accurate modeling of loads at a much more detailed level, and that will provide a better accounting of available savings and the economic value associated with them. Understanding the opportunities available to customers within defined and specific geographies, coupled with detailed load and economic information, will allow utilities to plan NWA approaches with greater confidence and to yield greater economic benefits (i.e. from the use of more granular, locational avoided costs) in the process. In recognition of this, several utilities and third party vendors are rapidly developing tools to address these emerging needs. We are aware of efforts by Integral Analytics for PG&E and others, and by Energy + Environmental Economics (E3) for Con Ed. Navigant is also participating in projects for both of these utilities, and it is likely that others are exploring this space as well.

Integral Analytics has developed a suite of proprietary software tools specifically for the purpose of providing utilities with previously unavailable capability for assessing loads down to the acre level, and for developing avoided costs that are specific to each circuit. These tools would not only provide California utilities with the means to comply with AB327, but would also allow them to assess the need for load relief with much greater precision and to plan NWAs more reliably. Integral Analytics has made special efforts to engage distribution planners in the development of their tools, in recognition of the importance of their participation in identifying and proposing NWAs.

E3 is working closely with Con Ed, as discussed above, to develop a "Decision Tool Integrator" that will overcome the earlier challenges the utility faced in accurately assessing the availability of savings, and further will allow them to identify the combinations of non-wires and traditional approaches that will be best suited to achieving the required load relief in specific areas.

## Impact Assessment

### 11. Impact Assessment Should Focus First on the T&D Reliability Need

Conceptually, assessment of geographically-targeted efficiency programs (and other non-wires resources for that matter) can address one or more of several key questions. Chief among them are:

1. Has the forecast T&D need changed? Has it moved further out into the future, or even been eliminated as a result of targeted programs?
2. To the extent that the forecast T&D need has changed, how much of that change is attributable to the deployment of geographically-targeted efficiency and/or other non-wires resources?
3. What is the magnitude of the T&D peak reduction (for efficiency or demand response) or production (for distributed generation or storage) that has been realized as a result of the deployment of efficiency and/or other non-wires resources? Note that the answer to this question might help inform the answer to the second question above.

To date, the principal focus of most jurisdictions' efforts to assess the impacts of NWAs has been on the first question: was the need for the T&D investment pushed out into the future? This is the most directly answerable question in the sense that it is really about how the current forecast of need has changed from the original forecast of need. It is also clearly the most important because it addresses the "bottom-line" metric that dictates whether money has been saved. In contrast, the second question – how much of the deferral is attributable to the non-wires alternatives – is challenging to address, in part because it begs the question of what "baseline" the evaluation is measuring against.

It is worth emphasizing that one of the key findings from non-wires projects has been that they often "buy time" to improve forecasts of need. Thus, one could argue that a non-wires solution should get "full credit" for a deferral even if the savings that the non-wires alternatives provided were not, by themselves, responsible for 100% of the difference between the old forecast and the new forecast of T&D need. As one Vermont official put it, in discussing a recent geo-targeting effort in the city of St. Albans:

> *"It is impossible to say that one thing deferred the project. But I would also argue that energy efficiency gave us the time to realize that we didn't need the project. As long as we follow a robust process for selecting geo-targeting areas, energy efficiency can be a 'no regrets' strategy, where even if it does not defer the project the efficiency investment is cost-effective (thanks to its avoided energy, capacity and other costs) and allows for more certainty as to the need for the infrastructure. In an energy system world where decisions must be made amidst so much uncertainty, geo-targeted efficiency's risk*

> *mitigation value increases above and beyond the risk value that we give to statewide programs."*[107]

That all said, traditional evaluation, measurement and verification (EM&V) of geographically targeted efficiency programs – both impact evaluation to determine how much T&D peak demand savings were realized and process evaluation to understand what worked well and what did not – can still provide a lot of value. However, that value may be more related to informing planning for future projects than for retrospectively "scoring" the effectiveness of the geo-targeting and/or assigning attribution for T&D deferrals.

[107] Personal communication with T.J. Poor, Vermont Public Service Department, December 23, 2014.

# VI. Policy Recommendations

In virtually every jurisdiction profiled in this report, the impetus for consideration of lower cost non-wires solutions to address selected reliability needs has been driven (at least initially) by some form of government policy – either legislative requirements, regulatory requirements or feedback, or both. In this section of the report, we present what lessons learned from leading jurisdictions suggests about key policies. Specifically, we offer four policies that policy-makers should consider if they are to effectively advance consideration of alternatives – including, but not limited to geographically targeted efficiency programs – to transmission and/or distribution system investments. Note that though we use the terminology "non-wires solutions" because most of the focus of this report has been on the electricity sector, the same concepts should apply to "non-pipes solutions" for the natural gas sector.

## Recommendation 1: Require Least Cost Approach to Meeting T&D Needs

This is the most basic, but also the most important policy for promoting consideration of alternatives to T&D investments. It is in place in every jurisdiction that is routinely assessing such alternatives on a routine basis. Because the barriers to non-wires alternatives – both institutional and financial – are so strong, this kind of requirement is necessary. It should be emphasized that though necessary, least cost requirements are not sufficient to ensure that economically optimal solutions to reliability needs are considered (see other policy recommendations below).

One other possible alternative would be an overhaul of the way utilities are regulated, including strong financial incentives for minimizing T&D costs imposed on ratepayers. That is the path that the state of New York appears to be pursuing. While intriguing, such a twist on the concept of performance regulation is untested and will be challenging to get right. That is not to say it should not be pursued – only that it needs to be done with great care, with regular evaluation to ensure it is producing the desired results, and perhaps with "backstop" minimum requirements to ensure that the expected and desired results are achieved.

## Recommendation 2: Require Long-Term Forecast of T&D Needs

One of the keys to realizing the full benefits that efficiency, demand response, distributed generation, storage and/or other non-wires solutions can provide is ensuring that they can deployed with sufficient lead time to defer T&D investments. We have highlighted several cases in this report in which non-wires solutions could have been less expensive than the wires solutions, but were not pursued (at least in part) because of concern that there was not enough lead time to be certain that the reliability need would be met. Requiring a long-term forecast of T&D investments can significantly reduce the probability of such less than optimal outcomes. By long-term we mean at least 10 years. However, 20 years – as is currently required in Vermont – may be even better. While the accuracy of these forecasts will diminish the farther out into the future they go, a 20 year forecast will still do a better job at ensuring that insufficient lead time does not preclude deployment of cost-effective non-wires solutions.

## Recommendation 3: Establish Screening Criteria for NWA Analyses

One way to help effectively institutionalize consideration of non-wires solutions is to establish a set of minimum criteria that would trigger a detailed assessment of non-wires solutions. Most of the jurisdictions discussed in this report have such criteria.

All such criteria start with a requirement that the project be load-related. As the Rhode Island guidelines put it, the need cannot be a function of the condition of the asset (e.g. to replace aging or malfunctioning equipment). Some jurisdictions, such as Vermont, have a short "form" that utilities must complete for each proposed project that provides more detail on this question.

Most jurisdictions have additional criteria related to one or more of the following:

- **Sufficient Lead Time Before Need.** The purpose of this criterion is to ensure that there is enough lead time to enable deferring a T&D investment.
- **Limits to the Size of Load Reduction Required.** The purpose of this criterion is to ensure that there is a substantial enough probability that the non-wires solution can be effective before investing in more detailed assessments. The maximum reduction can be linked to the previous criterion around lead time, as the longer the lead time the larger the reduction in load (and/or equivalent distributed generation level) that could be achieved through non-wires solutions.
- **Minimum Threshold for T&D Project Cost.** The purpose of this criterion is to ensure that the potential benefits of a T&D deferral are great enough to justify more detailed analysis.

Table 5 below provides a summary of the criteria currently in place for a number of the jurisdictions assessed in this report.

**Table 5: Criteria for Requiring Detailed Assessment of Non-Wires Solutions**

| | Must Be Load Related | Minimum Years Before Need | Maximum Load Reduction Required | Minimum T&D Project Cost | Source |
|---|---|---|---|---|---|
| **Transmission** | | | | | |
| Vermont | Yes | 1 to 3<br>4 to 5<br>6 to 10 | 15%<br>20%<br>25% | $2.5 Million | Regulatory policy |
| Maine | Yes | | | >69 kV or >$20 Million | Legislative standard |
| Rhode Island | Yes | 3 | 20% | $ 1 Million | Regulatory policy |
| Pacific Northwest (BPA) | Yes | 5 | | $3 Million | Internal planning criteria |
| **Distribution** | | | | | |
| PG&E (California) | Yes | 3 | 2 MW | | Internal planning criteria |
| Rhode Island | Yes | 3 | 20% | $ 1 Million | Regulatory policy |
| Vermont | Yes | | 25% | $0.3 Million | Regulatory policy |

Documents that lay out these requirements more formally and in more detail are provided for Vermont and Rhode Island in Appendices D, E and F.

Consistent with the integrated resource planning guideline discussed above, when projects pass such initial screening criteria, the utility should be required to conduct a more detailed assessment of the potential for reduced peak demand in the geographic area of interest through any combination of distributed resources, including additional energy efficiency, demand response, distributed generation and storage. The cost of such additional distributed resources should then be compared to their benefits. The level of depth of analysis would be a function of the magnitude of the deferral project. For projects for which the more detailed assessment suggests that greater EE and DR would have positive net benefits,[108] the utility should be required to pursue the non-wires solution.

## Recommendation 4: Promote Equitable Cost Allocation for NTAs

Investments in transmission solutions to reliability needs are commonly socialized across power pools. For example, a large majority of the cost of a transmission investment in Maine can ultimately be borne by ratepayers in the other five states that are part of the New England grid. In contrast, there is no comparable mechanism to socialize the cost of non-transmission investments across the region[109] – even if they would just as effectively address the reliability

[108] As discussed earlier in the report, some NWAs, including energy efficiency, provide a number of benefits beyond deferral of T&D investments. All costs and benefits of both NWAs and traditional T&D investments should be included in any economic comparisons.

[109] Note that though there is currently no mechanism for socializing the costs of implementing NTAs, there is at least an open question as to whether the costs of *analyzing* NTAs could be socialized. Indeed, some costs of analysis of

concern at a substantially lower cost. In other words, if Maine invests in a non-transmission solution, it will have to bear the full cost of that approach. This is a huge economic barrier to consideration of cost-effective non-transmission investments. Legislation in some states now requires their state officials to advocate for equal treatment of transmission and non-transmission planning and cost allocation in negotiations with and proceedings before their independent system operators, the Federal Energy Regulatory Commission (FERC) and other bodies and fora. Excerpts from the Vermont and Maine legislative language are provided below:

**Vermont Act 61, Section 8**

"(5) The public service department, public service board, and attorney general shall advocate for these policies in negotiations and appropriate proceedings before the New England Independent System Operator, the New England Regional Transmission Operator, the Federal Energy Regulatory Commission, and all other appropriate regional and national forums. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.

(6) In addressing reliability problems for the state's electric system, Vermont retail electricity providers and transmission companies shall advocate for regional cost support for the least cost solution with equal consideration and treatment of all available resources, including transmission, strategic distributed generation, targeted energy efficiency, and demand response resources on a total cost basis. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.

**Maine 2013 Omnibus Energy Bill, Part C, Sec. C-7 (35-A MRSA §3132)**

**15. Advancement of non-transmission alternatives policies**. The commission shall advocate in all relevant venues for the pursuit of least-cost solutions to bulk power system needs on a total cost basis and for all available resources, including non-transmission alternatives, to be treated comparably in transmission analysis, planning and access to funding.

The greater the number of states that have such policies in place, the greater the likelihood that this barrier will be addressed. The question of what "comparable treatment" to socialization of traditional transmission and non-transmission investments means is not necessarily a simple one. It is likely to require careful thought and discussion among a number of stakeholders. States can play an important role in pressing for and shaping such discussions.

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NTAs are already indirectly socialized. For example, VELCO, Vermont's transmission utility, currently recovers costs associated with its system planners through a regional tariff. Thus, when those planners work on NTAs, the costs of that work are effectively socialized across the regional. However, to our knowledge, no entity has yet tested whether other costs of analyzing NTAs (e.g. those born by other entities in a state) are recoverable through regional tariffs.

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# Appendix A: California AB 327 (excerpt)

SEC. 8. Section 769 is added to the Public Utilities Code, to read:

769. (a) For purposes of this section, “distributed resources” means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

(b) Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources. Each proposal shall do all of the following:

1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation.
2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.
3) Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.
4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.
5) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

(c) The commission shall review each distribution resources plan proposal submitted by an electrical corporation and approve, or modify and approve, a distribution resources plan for the corporation. The commission may modify any plan as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources.

(d) Any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan shall be proposed and considered as part of the next general rate case for the corporation. The commission may approve proposed spending if it concludes that ratepayers would realize net benefits and the associated costs are just and reasonable. The commission may also adopt criteria, benchmarks, and accountability mechanisms to evaluate the success of any investment authorized pursuant to a distribution resources plan.

# Appendix B: Maine 2013 Omnibus Energy Bill Excerpts

## An Act To Reduce Energy Costs, Increase Energy Efficiency, Promote Electric System Reliability and Protect the Environment

## PART C

**Sec. C-1. 35-A MRSA §3131, sub-§4-B** is enacted to read:

**4-B. Nontransmission alternative.** "Nontransmission alternative" means any of the following methods used either individually or combined to reduce the need for the construction of a transmission line under section 3132 or transmission project under section 3132-A: energy efficiency and conservation, load management, demand response or distributed generation.

**Sec. C-2. 35-A MRSA §3132, sub-§2-C, ¶¶B and C,** as enacted by PL 2009, c. 309, §2, are amended to read:

B. Justification for adoption of the route selected, including comparison with alternative routes that are environmentally, technically and economically practical; ~~and~~

C. Results of an investigation by an independent 3rd party, which may be the commission or a contractor selected by the commission, of nontransmission alternatives to construction of the proposed transmission line ~~including energy conservation, distributed generation or load management~~. The investigation must set forth the total projected costs of the transmission line as well as the total projected costs of the alternatives over the effective life of the proposed transmission line; and

**Sec. C-3. 35-A MRSA §3132, sub-§2-C, ¶D** is enacted to read:

D. A description of the need for the proposed transmission line.

**Sec. C-4. 35-A MRSA §3132, sub-§5,** as enacted by PL 1987, c. 141, Pt. A, §6, is amended to read:

**5. Commission approval of a proposed line.** The commission may approve or disapprove all or portions of a proposed transmission line and shall make such orders regarding its character, size, installation and maintenance as are necessary, having regard for any increased costs caused by the orders. The commission shall give preference to the nontransmission alternatives that have been identified as able to address the identified need for the proposed transmission line at lower total cost to ratepayers in this State. When the costs to ratepayers in this State of the identified nontransmission alternatives are reasonably equal, the commission shall give preference to the alternatives that produce the lowest amount of local air emissions, including greenhouse gas emissions.

**Sec. C-5. 35-A MRSA §3132, sub-§6,** as repealed and replaced by PL 2011, c. 281, §1, is amended to read:

**6. Commission order; certificate of public convenience and necessity.** In its order, the commission shall make specific findings with regard to the public need for the proposed transmission line. The commission shall make specific findings with regard to the likelihood that nontransmission alternatives can sufficiently address the identified public need over the effective life of the transmission line at lower total cost. Except as provided in subsection 6-A for a high-impact electric transmission line and in accordance with subsection 6-B regarding nontransmission alternatives, if the commission finds that a public need exists, after considering whether the need can be economically and reliably met using nontransmission alternatives, it shall issue a certificate of public convenience and necessity for the transmission line. In determining public need, the commission shall, at a minimum, take into account economics, reliability, public health and safety, scenic, historic and recreational values, state renewable energy generation goals, the proximity of the proposed transmission line to inhabited dwellings and alternatives to construction of the transmission line, including energy conservation, distributed generation or load management. If the commission orders or allows the erection of the transmission line, the order is subject to all other provisions of law and the right of any other agency to approve the transmission line. The commission shall, as necessary and in accordance with subsections 7 and 8, consider the findings of the Department of Environmental Protection under Title 38, chapter 3, subchapter 1, article 6, with respect to the proposed transmission line and any modifications ordered by the Department of Environmental Protection to lessen the impact of the proposed transmission line on the environment. A person may submit a petition for and obtain approval of a proposed transmission line under this section before applying for approval under municipal ordinances adopted pursuant to Title 30-A, Part 2, Subpart 6-A; and Title 38, section 438-A and, except as provided in subsection 4, before identifying a specific route or route options for the proposed transmission line. Except as provided in subsection 4, the commission may not consider the petition insufficient for failure to provide identification of a route or route options for the proposed transmission line. The issuance of a certificate of public convenience and necessity establishes that, as of the date of issuance of the certificate, the decision by the person to erect or construct was prudent. At the time of its issuance of a certificate of public convenience and necessity, the commission shall send to each municipality through which a proposed corridor or corridors for a transmission line extends a separate notice that the issuance of the certificate does not override, supersede or otherwise affect municipal authority to regulate the siting of the proposed transmission line. The commission may deny a certificate of public convenience and necessity for a transmission line upon a finding that the transmission line is reasonably likely to adversely affect any transmission and distribution utility or its customers.

**Sec. C-6. 35-A MRSA §3132, sub-§6-B** is enacted to read:

**6-B. Reasonable consideration of nontransmission alternatives.** If the commission determines that nontransmission alternatives can sufficiently address the transmission need under subsection 6 at lower total cost, but at a higher cost to ratepayers in this State than the proposed transmission line, the commission shall make reasonable efforts to achieve within 180 days an agreement among the states within the ISO-NE region to allocate the cost of the nontransmission alternatives among the ratepayers of the region using the allocation method used for transmission lines or a different allocation method that results in lower costs than the proposed transmission line to the ratepayers of this State.

For the purposes of this section, "ISO-NE region" has the same meaning as in section 1902, subsection 3.

The subsection is repealed December 31, 2015.

**Sec. C-7. 35-A MRSA §3132, sub-§15** is enacted to read:

**15. Advancement of nontransmission alternatives policies.** The commission shall advocate in all relevant venues for the pursuit of least-cost solutions to bulk power system needs on a total cost basis and for all available resources, including nontransmission alternatives, to be treated comparably in transmission analysis, planning and access to funding.

**Sec. C-8. 35-A MRSA §3132-A** is enacted to read:

## § 3132-A. Construction of transmission projects prohibited without approval of the commission

A person may not construct any transmission project without approval from the commission. For the purposes of this section, "transmission project" means any proposed transmission line and its associated infrastructure capable of operating at less than 69 kilovolts and projected to cost in excess of $20,000,000.

**1. Submission requirement.** A person that proposes to undertake in the State a transmission project must provide the commission with the following information:

A. Results of an investigation by an independent 3rd party, which may be the commission or a contractor selected by the commission, of nontransmission alternatives to construction of the proposed transmission project. The investigation must set forth the total projected costs of the transmission project as well as the total projected costs of the nontransmission alternatives over the effective life of the proposed transmission project; and

B. A description of the need for the proposed transmission project.

**2. Approval; consideration of nontransmission alternatives.** In order for a transmission project to be approved, the commission must consider whether the identified need over the effective life of the proposed transmission project can be economically and reliably met using nontransmission alternatives at a lower total cost. During its review the commission shall give preference to nontransmission alternatives that are identified as able to address the identified need for the proposed transmission project at lower total cost to ratepayers. Of the identified nontransmission alternatives, the commission shall give preference to the lowest-cost nontransmission alternatives. When the costs to ratepayers of the identified nontransmission alternatives are reasonably equal, the commission shall give preference to the alternatives that produce the lowest amount of local air emissions, including greenhouse gas emissions.

**3. Exception.** A transmission project that is constructed, owned and operated by a generator of electricity solely for the purpose of electrically and physically interconnecting the generator to the transmission system of a transmission and distribution utility is not subject to this section.

# Appendix C: Vermont Act 61 Excerpts

Sec. 8. ADVOCACY FOR REGIONAL ELECTRICITY RELIABILITY POLICY

It shall be the policy of the state of Vermont, in negotiations and policy-making at the New England Independent System Operator, in proceedings before the Federal Energy Regulatory Commission, and in all other relevant venues, to support an efficient reliability policy, as follows:

(1) When cost recovery is sought through region-wide regulated rates or uplift tariffs for power system reliability improvements, all available resources – transmission, strategic generation, targeted energy efficiency, and demand response resources – should be treated comparably in analysis, planning, and access to funding.

(2) A principal criterion for approving and selecting a solution should be whether it is the least-cost solution to a system need on a total cost basis.

(3) Ratepayers should not be required to pay for system upgrades in other states that do not meet these least-cost and resource-neutral standards.

(4) For reliability-related projects in Vermont, subject to the review of the public service board, regional financial support should be sought and made available for transmission and for distributed resource alternatives to transmission on a resource-neutral basis.

(5) The public service department, public service board, and attorney general shall advocate for these policies in negotiations and appropriate proceedings before the New England Independent System Operator, the New England Regional Transmission Operator, the Federal Energy Regulatory Commission, and all other appropriate regional and national forums. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.

(6) In addressing reliability problems for the state's electric system, Vermont retail electricity providers and transmission companies shall advocate for regional cost support for the least cost solution with equal consideration and treatment of all available resources, including transmission, strategic distributed generation, targeted energy efficiency, and demand response resources on a total cost basis. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.

* * * Transmission and Distribution Planning * * *

Sec. 9. 30 V.S.A. § 218c is amended to read:

§ 218c. LEAST COST INTEGRATED PLANNING

(d)(1) Least cost transmission services shall be provided in accordance with this subsection. Not later than July 1, 2006, any electric company that does not have a designated retail service territory and that owns or operates electric transmission facilities within the state of Vermont, in conjunction with any other electric companies that own or operate these facilities, jointly shall prepare and file with the department of public service and the public service board a transmission system plan that looks forward for a period of at least ten years. A copy of the plan shall be filed with each of the following: the house committees on commerce and on natural resources and energy and the senate committees on finance and on natural resources and energy. The objective of the plan shall be to identify the potential need for transmission system improvements as early as possible, in order to allow sufficient time to plan and implement more cost-effective non-transmission alternatives to meet reliability needs, wherever feasible. The plan shall:

(A) identify existing and potential transmission system reliability deficiencies by location within Vermont;

(B) estimate the date, and identify the local or regional load levels and other likely system conditions at which these reliability deficiencies, in the absence of further action, would likely occur;

(C) describe the likely manner of resolving the identified deficiencies through transmission system improvements;

(D) estimate the likely costs of these improvements;

(E) identify potential obstacles to the realization of these improvements; and

(F) identify the demand or supply parameters that generation, demand response, energy efficiency or other non-transmission strategies would need to address to resolve the reliability deficiencies identified.

(2) Prior to the adoption of any transmission system plan, a utility preparing a plan shall host at least two public meetings at which it shall present a draft of the plan and facilitate a public discussion to identify and evaluate non-transmission alternatives. The meetings shall be at separate locations within the state, in proximity to the transmission facilities involved or as otherwise required by the board, and each shall be noticed by at least two advertisements, each occurring between one and three weeks prior to the meetings, in newspapers having general circulation within the state and within the municipalities in which the meetings are to be held. Copies of the notices shall be provided to the public service board, the department of public

service, any entity appointed by the public service board pursuant to subdivision 209(d)(2) of this title, the agency of natural resources, the division for historic preservation, the department of health, the scenery preservation council, the agency of transportation, the attorney general, the chair of each regional planning commission, each retail electricity provider within the state, and any public interest group that requests, or has made a standing request for, a copy of the notice. A verbatim transcript of the meetings shall be prepared by the utility preparing the plan, shall be filed with the public service board and the department of public service, and shall be provided at cost to any person requesting it. The plan shall contain a discussion of the principal contentions made at the meetings by members of the public, by any state agency, and by any utility.

(3) Prior to the issuance of the transmission plan or any revision of the plan, the utility preparing the plan shall offer to meet with each retail electricity provider within the state, with any entity appointed by the public service board pursuant to subdivision 209(d)(2) of this title, and with the department of public service, for the purpose of exchanging information that may be relevant to the development of the plan.

(4) (A) A transmission system plan shall be revised:

(i) within nine months of a request to do so made by either the public service board or the department of public service; and

(ii) in any case, at intervals of not more than three years.

(B) If more than 18 months shall have elapsed between the adoption of any version of the plan and the next revision of the plan, or since the last public hearing to address a proposed revision of the plan and facilitate a public discussion that identifies and evaluates nontransmission alternatives, the utility preparing the plan, prior to issuing the next revision, shall host public meetings as provided in subdivision (2) of this subsection, and the revision shall contain a discussion of the principal contentions made at the meetings by members of the public, by any state agency, and by any retail electricity provider.

(5) On the basis of information contained in a transmission system plan, obtained through meetings held pursuant to subdivision (2) of this subsection, or obtained otherwise, the public service board and the department of public service shall use their powers under this title to encourage and facilitate the resolution of reliability deficiencies through nontransmission alternatives, where those alternatives would better serve the public good. The public service board, upon such notice and hearings as are otherwise required under this title, may enter such orders as it deems necessary to encourage, facilitate or require the resolution of reliability deficiencies in a manner that it determines will best promote the public good.

(6) The retail electricity providers in affected areas shall incorporate the most recently filed transmission plan in their individual least cost integrated planning processes, and shall cooperate

as necessary to develop and implement joint least cost solutions to address the reliability deficiencies identified in the transmission plan.

(7) Before the department of public service takes a position before the board concerning the construction of new transmission or a transmission upgrade with significant land use ramifications, the department shall hold one or more public meetings with the legislative bodies or their designees of each town, village, or city that the transmission lines cross, and shall engage in a discussion with the members of those bodies or their designees and the interested public as to the department's role as public advocate.

# Appendix D: Rhode Island Standards for Least Cost Procurement and System Reliability Planning (excerpt)

**Chapter 2- System Reliability Procurement**

<u>Section 2.1 Distributed/Targeted Resources in Relation to T&D Investment</u>

A. The Utility System Reliability Procurement Plan ("The SRP Plan") to be submitted for the Commission's review and approval on September 1, 2011 and triennially thereafter on September 1, shall propose general planning principles and potential areas of focus that incorporate non-wires alternatives (NWA) into the Company's distribution planning process for the three years of implementation beginning January 1 of the following year.

B. Non-Wires Alternatives (NWA) may include but are not limited to:
   a. Least Cost Procurement energy efficiency baseline services.
   b. Peak demand and geographically-focused supplemental energy efficiency strategies
   c. Distributed generation generally, including combined heat and power and renewable energy resources (predominately wind and solar, but not constrained)[110]
   d. Demand response
   e. Direct load control
   f. Energy storage
   g. Alternative tariff options

C. Identified transmission or distribution (T&D) projects with a proposed solution that meet the following criteria will be evaluated for potential NWA that could reduce, avoid or defer the T&D wires solution over an identified time period.
   a. The need is not based on asset condition.
   b. The wires solution, based on engineering judgment, will likely cost more than $1 million;
   c. If load reductions are necessary, then they are expected to be less than 20 percent of the relevant peak load in the area of the defined need;
   d. Start of wires alternative is at least 36 months in the future; and

   A more detailed version of these criteria may be developed by the distribution utility with input from the Council and other stakeholders.

D. Feasible NWAs will be compared to traditional solutions based on the following:
   a. Ability to meet the identified system needs;
   b. Anticipated reliability of the alternatives;

---

[110] In order to meet the statute's environmental goals, generation technologies must comply with all applicable general permitting regulations for smaller-scale electric generation facilities.

c. Risks associated with each alternative (licensing and permitting, significant risks of stranded investment, sensitivity of alternatives to differences in load forecasts, emergence of new technologies)
d. Potential for synergy savings based on alternatives that address multiple needs
e. Operational complexity and flexibility
f. Implementation issues
g. Customer impacts
h. Other relevant factors

E. Financial analyses of the preferred solution(s) and alternatives will be conducted to the extent feasible. The selection of analytical model(s) will be subject to Public Utilities Commission review and approval. Alternatives may include the determination of deferred investment savings from NWA through use of net present value of the deferred revenue requirement analysis or the net present value of the alternatives according to the Total Resource Cost Test (TRC). The selection of an NWA shall be informed by the considerations approved by the Public Utilities Commission which may include, but not be limited to, those issues enumerated in (D), the deferred revenue requirement savings and an evaluation of costs and benefits according to the TRC. Consideration of the net present value of resulting revenue requirements may be used to inform the structure of utility cost recovery of NWA investments and to assess anticipated ratepayer rate and bill impacts.

F. For each need where a NWA is the preferred solution, the distribution utility will develop an implementation plan that includes the following:
    a. Characterization of the need
        i. Identification of the load-based need, including the magnitude of the need, the shape of the load curve, the projected year and season by which a solution is needed, and other relevant timing issues.
        ii. Identification and description of the T&D investment and how it would change as a result of the NWA
        iii. Identification of the level and duration of peak demand savings and/or other operational functionality required to avoid the need for the upgrade
        iv. Description of the sensitivity of the need and T&D investment to load forecast assumptions.
    b. Description of the business as usual upgrade in terms of technology, net present value, costs (capital and O&M), revenue requirements, and schedule for the upgrade
    c. Description of the NWA solution, including description of the NWA solution(s) in terms of technology, reliability, cost (capital and O&M), net present value, and timing.
    d. Development of NWA investment scenario(s)
        i. Specific NWA characteristics

ii. Development of an implementation plan, including ownership and contracting considerations or options
iii. Development of a detailed cost estimate (capital and O&M) and implementation schedule.

G. Funding Plan

The Utility shall develop a funding plan based on the following sources to meet the budget requirement of the system reliability procurement plan. The Utility may propose to utilize funding from the following sources for system reliability investments:

i. Capital funds that would otherwise be applied towards traditional wires based alternatives;

ii. Existing Utility EE investments as required in Section I of these Standards and the resulting Annual Plans.

iii. Additional energy efficiency funds to the extent that the NWA can be shown to pass the TRC test with a benefit to cost ratio of greater than 1.0 and such additional funding is approved;

iv. Utility operating expenses to the extent that recovery of such funding is explicitly allowed;

v. Identification of significant customer contribution or third party investment that may be part of a NWA based on benefits that are expected to accrue to the specific customers or third parties.

vi. Any other funding that might be required and available to complete the NWA.

H. Annual SRP Plan reports should be submitted on November 1. Such reports will include but are not limited to:
   a. A summary of projects where NWA were considered;
   b. Identification of projects where NWA were selected as a preferred solution; and a summary of the comparative analysis following the criteria outlined in sections (D) and (E) above;
   c. Implementation plan for the selected NWA projects;
   d. Funding plan for the selected NWA projects;
   e. Recommendations on pilot distribution and transmission project alternatives for which it will utilize selected NWA reliability and capacity strategies. These proposed pilot projects will be used to inform or revise the system reliability procurement process in subsequent plans;
   f. Status of any previously selected and approved projects and pilots;

g. Identification of any methodological or analytical tools to be developed in the year;
h. Total SRP Plan budget, including administrative and evaluation costs.

I. The Annual SRP Plan will be reviewed and funding approved by the Commission prior to implementation.

# Appendix E: Vermont Non-Transmission Alternatives Screening Form (9/27/12)

*For use in screening to determine whether or not a transmission system **reliability issue** requires non-transmission alternatives (NTA) analysis in accordance with the Memorandum of Understanding in Docket 7081. Projects intended for energy market-related purposes – "economic" transmission – and other non-reliability-related projects do not fall within the scope of the Docket 7081 process.*

**Identify the proposed upgrade:**

______________________________________________

**Date of analysis:** ______________________________________________

1. Does the project meet one of the following criteria that define the term "impracticable" *(check all that apply)*?
   a. Needed for a redundant supply to a radial load; or ❑
   b. Maintenance-related, addressing asset condition, operations, or safety; or ❑
   c. Addressing transmission performance, e.g., addition of high-speed protection or a switch to sectionalize a line; or ❑
   d. Needed to address stability or short circuit problems;[111] or ❑
   e. Other technical reason why NTAs are impracticable. *Attach detailed justification that must be reviewed by the VSPC.* ❑

   *If any box above is checked, project screens out of full NTA analysis.*

2. What is the proposed transmission project's need date? ______________________
   *If the need for the project is based on existing or imminent reliability criteria violations (i.e., arising within one year based on the controlling load forecast), project screens out of full NTA analysis.*

[111] "Stability" refers to the ability of a power system to recover from any disturbance or interruption. Instability can occur when there is a loss of synchronism at one or more generators (rotor angle stability), a significant loss of load or generation within the system (frequency stability), or a reactive power deficiency (voltage stability). Stability problems are influenced by system parameters such as transmission line lengths and configuration, protection component type and speed, reactive power sources and loads, and generator type and configuration. Due to the nature of instability, non-transmission alternatives involving addition of generation or reduction of load will not solve these problems.

| | | |
|---|---|---|
| 3. | Could elimination or deferral of all or part of the upgrade be accomplished by a 25% or smaller load reduction or off-setting generation of the same magnitude? *(See note.)*<br>*If "no," project screens out of full NTA analysis.* | ❑ Yes<br>❑ No |
| 4. | Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $2.5 million. *(See note.)*<br>*If "no," project screens out of full NTA analysis.* | ❑ Yes<br>❑ No |

Sign and date this form.

This analysis performed by: ____________________________

*Print name & title*

____________________________

*Company*

____________________________

*Date*

____________________________

*Signature*

# NTA Screening Form
# Notes, examples and descriptions

Line 3 Non-transmission alternatives should be considered if the project can be altered or deferred with load reductions or off-setting generation, according to the schedule below, of existing peak load of the affected area at the time of the need for the preferred transmission alternatives. This schedule recognizes that deployment of a load reduction program in a specific area takes time to organize and implement. Therefore, the following assumptions including time and accrued load reduction should be considered when examining the load reduction:

| **Period** | **Magnitude of load reduction and/or off-setting generation** |
|---|---|
| 1-3 years | 15% of peak load |
| 5 years | 20% of peak load |
| 10 years | 25% of peak load |

Line 4 The $2.5 million is in year 2012 dollars and is adjusted for escalation in future years using the Handy Whitman transmission cost index. This threshold does not account for the expected costs of the NTAs, but rather only includes the expected savings to the cost of the transmission project.

## Appendix F: Vermont Form for Selection of Distributed Utility Planning Areas (v. 28, 10/1/02)

*The purpose of this form is to (1) guide the selection of DUP areas while (2) documenting which criteria apply to the decision.*

Identity of the upgrade (description or project number): ______________________________

________________________________________________________________________________

| | | |
|---|---|---|
| 1. | Is the cost of the upgrade greater than $2,000,000? *(See note.)*<br><br>*If so, check "Yes" and continue to Line 4; otherwise check "No" and. continue to Line* 2 | Yes .☐<br>No ..☐ |
| 2. | Would the upgrade relieve a T&D delivery constraint in a Capacity Constrained Area? *(See note.)*<br><br>*If so, check "Yes" and continue to Line* 3*; otherwise check "No" and* exclude *the expected upgrade from DU analysis.* | Yes .☐<br>No ..☐ |
| 3. | Is the cost of the upgrade less than $250,000? *(See note.)*<br><br>*If so, check "Yes" and* exclude *the expected upgrade from DU analysis; otherwise check "No" and continue to Line 4.* | Yes .☐<br>No ..☐ |
| 4. | Is the upgrade driven by an emergency situation requiring the immediate replacement of equipment that has failed or is at imminent risk of failure?<br><br>*If so, check "Yes" and* exclude *the upgrade from DU analysis; otherwise check "No" and continue to line 5.* | Yes .☐<br>No ..☐ |
| 5. | Does the upgrade constitute a minor change for the purpose of system tuning or efficiency improvements? *(See note.)*<br><br>*If so, check "Yes," indicate which of the below upgrades are included (check all that apply), and* exclude *the upgrade from DU analysis. Otherwise check "No" and continue to line 6.* | Yes .☐<br>No ..☐ |
| 5.a | • installation or changes to relays, reclosers, fuses, switches, sectionalizers, breakers, breaker bypass switches, MOABs, capacitors, regulators, arresters, insulators, or meters ........................................................................ | ☐ |
| 5.b | • installation or replacement of underground getaways..................................... | ☐ |

| | | | |
|---|---|---|---|
| 5.c | • | upgrade of substation bus work........................................................................ | ☐ |
| 5.d | • | upgrade of substation structural work, fencing, or oil containment................. | ☐ |
| 5.e | • | installation or upgrade to SCADA .................................................................. | ☐ |
| 5.f | • | transformer swaps .......................................................................................... | ☐ |
| 5.g | • | addition of fans to transformers ..................................................................... | ☐ |
| 5.h | • | balancing of feeder phases ............................................................................ | ☐ |
| 5.i | • | replacement of deteriorated poles, crossarms, structures, poles and conduit; and<br>replacement of wires on such equipment with the least-cost wires. *(See note.)*................................................................................................ | ☐ |
| 5.j | • | Other (please describe):<br>______________________________<br>______________________________<br>______________________________<br>______________________________ (Attach further explanation if needed.)) | ☐ |
| 6. | | Is the upgrade a line-reconstruction project pursuant to joint use agreements with telephone or CATV or pole-attachment tariff requirements?<br><br>*If so, check "Yes" and* exclude *the upgrade from DU analysis; otherwise check "No" and continue to line 7.* | Yes .☐<br>No ..☐ |
| 7. | | Is the upgrade the result of a customer's request for a specific equipment or service for which distributed resources would not be acceptable? *(See note.)*<br><br>*If so, check "Yes," describe the situation,* ______________________________<br>______________________________<br>______________________________<br>______________________________<br><br>*and* exclude *the expected upgrade from DU analysis; otherwise check "No" and continue to line 8.* | Yes .☐<br>No ..☐ |
| 8. | | Is the upgrade required to remedy reliability, stability, or safety problems? | Yes .☐<br>No ..☐ |

*If so, check "Yes" and continue to line 9; otherwise check "No" and skip to line 11.*

| | | |
|---|---|---|
| 9. | Could the scope and cost of the resulting project be reduced by a reduction in load level or by the installation of distributed generation? *(See note to clarify the extent of load reduction.)*<br><br>*If so, check "Yes" and continue to line 10; otherwise check "No" and skip to line 11.* | Yes .☐<br>No ..☐ |
| 10. | Is the likely reduction in costs from the potential reduction in scope less than $250,000? *(See note.)*<br><br>*If so, check "Yes" and* exclude *the upgrade from DU analysis; otherwise check "No" and continue to line 11.* | Yes .☐<br>No ..☐ |
| 11. | Would load reduction or generation allow for the elimination or deferral of all of the upgrade? *(See note to clarify the extent of load reduction.).*<br><br>*If so, check "Yes" and proceed to* define *the scope and timing of the local DU analysis; otherwise check "No" and continue to line 12.* | Yes .☐<br>No ..☐ |
| 12. | Can the upgrade be implemented with different levels of capacity in the replacement equipment, with costs that could differ by more than $250,000?<br><br>*If not, check "No" and* exclude *the expected upgrade from DU analysis; otherwise check "Yes" and proceed to* define *the scope and timing of the local DU analysis.* | Yes .☐<br>No ..☐ |

**Remember to sign and date this form.**

This analysis performed by ____________________ on ____________________

*Name* *Date*

____________________

*Print Name*

**Notes, Examples, and Descriptions**

| | |
|---|---|
| Line 1 | Any T&D project whose capital cost is expected to exceed $2 million (in year 2002 dollars, adjusted for inflation in future years), including any reasonably foreseeable related projects, sub-projects, and multiple phases, should be reviewed for the applicability of DUP. |
| Line 2 | DUs may exclude from DUP analysis Non-Constrained Area Projects, as defined in the Docket No. 6290 MOU, of $2 million or less (determined as described in the note to line 1). |
| Line 3 | Projects of less than $250,000 (in year 2002 dollars, adjusted for inflation in future years) may be excluded from DUP analysis. This step is intended to identify constrained situations in which the DU study would be disproportionately costly, compared to the budgeted project cost. |
| Line 5: | Minor projects that are only parts of a larger project should not be screened using this step. For example, a substation rebuild would include many of the items listed in 5.a–j, but would not be a project that is minor in size and scope. Therefore, larger projects such as substation rebuilds should be analyzed according to the criteria in lines 7 through 12. |
| Line 5i: | These situations do not include upgrading equipment *specifically* to *significantly* increase capacity, which should be reviewed at lines 11 and 12. |
| Line 7: | For example, the customer may be willing to pay for a distribution upgrade, but not for distributed resources. In other situations, the customer may be willing to pay for distributed resources, but may be unwilling to have the distributed resources on its premises, and resources elsewhere may not provide the required service. |
| Lines 9 and 11: | If reduction in present load by 25% and the elimination of all load growth would not affect the need for the project, or its cost, the project may be considered to be independent of load. The feasibility of the required load reductions will be reviewed in the resource-scoping stage of the DU analysis.<br><br>The determination that load reductions would not avoid a particular investment can be established by reference to an approved policy (such as standards adopted to capture lost opportunities or simplify system operations). If so, indicate the document that specifies the policy. |
| Line 10: | This line addresses situations in which the upgrade is driven by considerations other than load growth, but the upgrade could be avoided, in whole or in part, by load reductions or distributed generation. Examples of situations in which significant costs may be avoidable, even though some part of the project is unavoidable, include the following:<br><br>• Replacement of large transformers<br><br>• looping projects or adding tie-lines to create first-contingency reliability |

More rarely load reductions may reduce the costs of

- line relocations due to road or bridge reconstruction
- line relocations in response to local, state, or federal requests
- line rebuilds due to deterioration

Examples of situations in which loads would matter for these latter projects include (1) capacity increases planned to coincide with the relocation or rebuilding, and (2) lines that serve no customers along a considerable distance (e.g., over a mountain or through a wetland), where reduced loads at the other end of the line could be picked up by other facilities.

Lines 10 and 12: The $250,000 is in year 2002 dollars, to be adjusted for inflation in future years.

RAP Energy solutions for a changing world

# US Experience with Efficiency As a Transmission and Distribution System Resource

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Though we could not have completed this report without the help of those identified above, it is important to note that some of the feedback we received was conflicting. In addition, in a few cases, we disagreed with and therefore elected not to make some specific changes suggested by one or more reviewers. We make these points to underscore that we, the authors, are ultimately solely responsible for the information presented and the conclusions drawn in the report.

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# Executive Summary

Improvements to electric efficiency in homes and business provide a variety of benefits to both the customers making the improvements and to the electric system as a whole. The most widely recognized are energy savings and system peak demand savings. A much less widely recognized or valued benefit is the potential to enhance the reliability of the transmission and distribution (T&D) system. This paper focuses on that potential, summarizing lessons learned from US initiatives in which geographically targeted efficiency programs have played a major role in electric utility funded efforts to defer T&D investments.

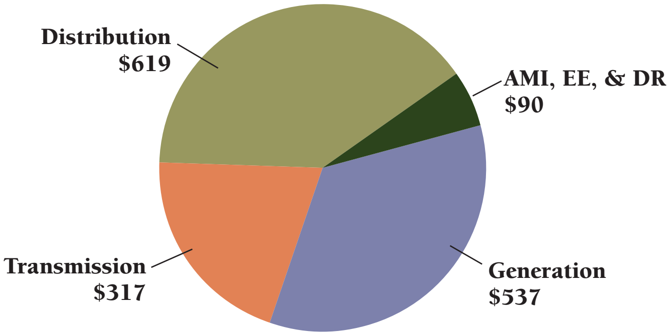
## Importance of T&D Investments

The potential to defer T&D upgrades deserves much more serious consideration than it has received to date. The U.S. utility sector has invested on the order of $35 to $40 billion per year in the T&D system over the past decade and is forecast to invest nearly $50 billion per year over the next two decades. As Figure ES-1 shows, this represents approximately 60% of total forecast investments for the sector. Only 6% of the forecast capital investments are in advanced metering infrastructure (AMI), energy efficiency (EE) and demand response (DR). Not all forecast T&D investments will be deferrable. Some will be required to address time-related deterioration of equipment or other factors that are independent of load. However, a significant portion of T&D investment is likely to be associated with load growth. The potential benefits of deferring even a modest portion of such investments could be substantial.

*Figure ES-1*

**US Power Sector Capital Investment Needs (2010 – 2030)**

*(in billions of 2009 dollars)*




### Passive Deferral vs. Active Deferral

Efficiency programs can defer T&D investments either passively or actively. We define "passive deferrals" as those that occur as a result of efficiency programs that were not undertaken primarily for the purpose of deferring T&D upgrades. For example, system-wide efficiency programs will reduce loads on virtually all major elements of the T&D system. As a result, at least some load growth-related investments in the T&D system will be deferred for at least some period of time. Indeed, Consolidated Edison (Con Ed) reduced its projected T&D capital expenditures by more than $1 billion after separately adjusting 10-year load forecasts for each of its 91 distribution networks and load areas in New York to reflect the expected impacts of system-wide efficiency programs.

In contrast, "active deferrals" are those that result from efficiency programs that are geographically-targeted for the express purpose of deferring the need for upgrades to specific elements of the T&D infrastructure. Though there are a number of notable exceptions, this concept has not yet been widely pursued due to a variety of inter-related factors:

- **Financial incentives –** utilities typically earn more from investing in "poles and wires" than from investing in efficiency and/or other alternatives;
- **Efficiency's multiple attributes/benefits –** because efficiency investments provide energy savings, peak capacity savings, reserve margin savings, and other benefits in addition to T&D reliability improvements, comparing them to "poles and wires" investments requires a holistic, systemic perspective that has not been universally adopted by utilities, their regulators, independent system operators (ISOs), or regional transmission operators (RTOs);
- **System planning is highly technical –** the technical specialization needed to do T&D planning fosters an environment biased to technical solutions;
- **System engineers distrust demand resources –** those charged with planning to meet reliability needs typically have limited interaction with efficiency program managers and limited direct experience with the performance of demand resources;



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- **Risk aversion –** utilities are typically reluctant to try new approaches, particularly if they perceive any regulatory risk in doing so;
- **Socialization of transmission investment costs** – while the cost of transmission solutions are often socialized regionally, the cost of efficiency programs or other non-wires solutions that could meet the same reliability objectives are not; and
- **Responsibility for transmission planning is diffuse** – with state regulators, utilities, independent system operators or regional transmission operators and the Federal Energy Regulatory Commission all having roles, it is difficult for a new approach (i.e. non-wires solutions) to gain traction.

## U.S. Experience with Active Deferrals of T&D Investments through Efficiency

Though far from widespread, a number of jurisdictions have tested and/or are in the process of testing the role that geographically-targeted efficiency programs could play in cost-effectively deferring T&D investments. This paper examines ten different initiatives or policies – four in the 1990s and six others that are much more recent and/or still underway. As summarized below, this experience provides valuable lessons to guide future policies for the successful deployment of energy efficiency as a T&D resource.

### Pacific Gas and Electric's Delta Project (California, early 1990s)

The project aimed to defer the need for a new substation that would otherwise be required to serve a growing community of 25,000 homes and 3000 businesses in far eastern Contra Costa County. Several efficiency programs were quickly launched in the region to reduce peak loads, with more than 10% of homes receiving some major measures. The project did defer the need for the substation for at least two years, though at a higher cost than expected because some measures provided much lower peak savings than expected. While other measures provided greater savings than expected, the compressed timeframe for the project did not allow for switching of strategies early enough to keep average costs at more reasonable levels.

### Portland General Electric's Downtown Portland Pilot (Oregon, early 1990s)

This project focused on several opportunities. In the case of individual buildings where load reductions were needed to defer transformer upgrades, the utility aggressively marketed existing system-wide efficiency programs to the building owners. For grid network objectives, where peak demand reductions of 10-20% for entire 10-15 block areas were needed, the utility contracted with energy service companies (ESCOs) to deliver savings. Results were mixed. For one building, savings were enough to defer and possibly permanently eliminate the need for a $250,000 upgrade. In another building an unexpected conversion from gas to electric cooling eliminated any opportunity to defer the upgrade. The ESCOs contracted to achieve savings in a grid area network succeeded in reducing peak load by more than the 20% required. However, the utility's distribution engineering staff decided to proceed with their construction project before the savings were documented.

### BPA's Puget Sound Area Electric Reliability Plan (Washington, early 1990s)

The Bonneville Power Administration (BPA) and local utilities decided to address a transmission reliability concern through a strategy of adding voltage support to the existing transmission system (the most important part of the strategy) and more intensive deployment of energy efficiency programs (a complementary element). The project ended up delaying construction of a new cross-Cascade transmission line for more than a decade.

### Green Mountain Power's Mad River Valley Project (Vermont, mid to late 1990s)

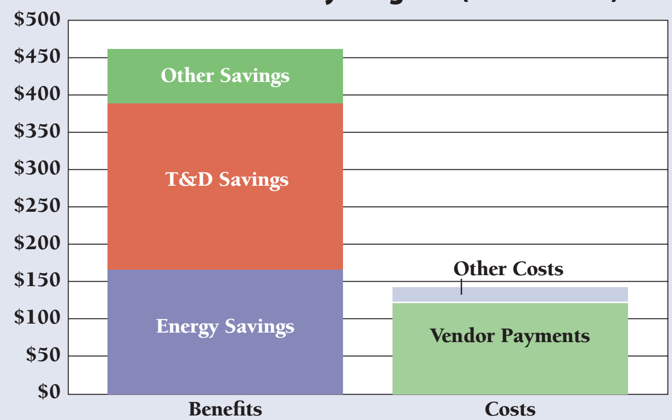
The project aimed to defer the need for a new distribution line in an area dominated by a large ski resort which had announced expansion plans that would add 15 MW of new load to the system. When it became clear that the resort may be required by Vermont regulations to bear most of the cost, negotiations between the utility, the resort and the state's rate-payer advocate led to an alternative plan in which the resort would better manage its load to ensure that total loads were within existing system tolerances and the utility would aggressively pursue efficiency improvements with its customers in the region. In the end, the project succeeded with the efficiency programs coming close to achieving overall savings goals.

### Consolidated Edison (New York City, early 2000s to present)

In 2003, Con Ed launched a program to defer distribution system upgrades using a competitive bidding process to select the resources it would pursue. To date, only efficiency resources have been selected. To address reliability concerns, contracts for those resources include both significant upfront security and downstream liquidated damage provisions. All told, between 2003 and 2010, the Company employed geographically-targeted efficiency programs to defer upgrades in more than one third of its distribution networks. The resulting savings were very close to forecast needs and, as Figure ES-2 shows, provided more than $300 million in net benefits to ratepayers. In some cases, the efficiency investments not only deferred upgrades, but bought enough time to allow the utility to refine load forecasts to the point where it now believes that capacity extensions may never be needed.

*Figure ES-2*

**Net Present Value of Benefits and Costs of Con Ed T&D Efficiency Program (2003–2010)**




### Efficiency Vermont Geo-Targeted DSM (2007 to present)

Efficiency Vermont's performance goals were modified to include not only system wide savings targets, but also much more aggressive targets in selected geographic areas which the state's utilities had identified as candidates for deferring T&D investments. The initiative has had some success. Although peak demand savings in the targeted areas were at least 30% below targets, they were still three to five times greater than those achieved statewide (notable since the statewide savings were already the highest in the nation). The state's largest utility has observed that it has not had to schedule deployment of additional system upgrades in the targeted areas. The extent to which that is attributable to the geo-targeted efficiency programs, changes in economic conditions, other factors has not yet been determined.

### NV Energy (Nevada, late 2000s)

NV Energy launched an efficiency initiative in and around Carson City in an effort to obviate the need to either run the locally situated but relatively expensive Fort Churchill generating station more frequently or construct a new transmission line and substation to bring less expensive power into the region. At the same time, the utility began re-conductoring the existing 120-kVA line to the region. An economic recession also hit at the same time, dampening growth. As a result, the Company has not had to revisit the need for either running the Fort Churchill station more often or adding new T&D capacity.

### Central Maine Power (currently under development)

In 2010, the Maine regulators approved a settlement agreement that supported construction of most elements of a large transmission project, but identified two areas – the Mid-Coast region and the city of Portland – where pilot projects to test the efficacy of non-transmission alternatives would be launched. In March 2011, Central Maine Power filed a plan for the Mid-Coast region that proposed using a competitive process to identify and acquire needed distributed resources. The plan suggested that efficiency resources were expected to be "highly competitive". A variety of issues regarding both the forecast capacity needs and the process for acquiring distributed resources were unresolved as this report was being finalized.

### National Grid (Rhode Island, currently under development)

In 2006, Rhode Island adopted a "System Reliability Procurement" policy that required utilities to file plans every three years. The plans must consider non-wires alternatives – including energy efficiency – whenever a T&D need is not based on an asset condition, would cost more than $1 million, would require no more than a 20% reduction in load to defer and would not require investment in a "wires solution" for at least three years. Based on these guidelines, in late 2011, National Grid proposed an initial pilot project to defer the upgrading of a substation through a combination of load management and energy efficiency.

### Bonneville Power Authority (Washington, Oregon and Idaho, currently under consideration)

In 2002, the Bonneville Power Authority launched an initiative in which it committed to investigating options for deferring potential transmission reinforcement projects. A year later, it formed a Non-Wires Solutions Round Table of key stakeholder groups to provide input to its work. It then developed a formal process by which transmission alternatives – including efficiency – would be assessed. That process includes an initial screening to determine if a project is a possible candidate for a non-wires solution. The project qualifies if it is estimated to cost at least $5 million, it is driven by load growth and the need is at least eight years in the future. Bonneville is currently conducting detailed feasibility assessments of non-wires solutions to three projects – one each in Oregon, Washington and Idaho – that passed this initial screen. In each case, efficiency is part of a package of options being considered.

## Lessons Learned

Our review of these efforts to use efficiency programs to defer T&D investments – alone or in concert with other resources – leads us to the following initial conclusions:

- **Geographically-targeted efficiency can defer T&D investments.** That appears to have been the case in New York City; Vermont's Mad River Valley; Portland, Oregon; and Contra Costa County, California.
- **Efficiency can be a cost-effective T&D resource.** There is less evidence regarding the cost-effectiveness of efficiency as an alternative to T&D investments. However, analysis of the most intensive and longest-standing effort – Con Ed's experience in New York City – concluded that T&D savings alone out-weighed the cost of efficiency. When all efficiency benefits are considered, the initiative had a three-to-one benefit-cost ratio.
- **Unexpected events can affect the benefits of efficiency.** In several of the cases analyzed, some or all of the T&D investment being considered for deferral ended up being constructed for reasons having nothing to do with the effectiveness of deployment of efficiency resources. However, forecasting uncertainty works in both directions. Indeed, in a couple of cases, efficiency investments bought enough time to enable a utility to conclude that – contrary to initial forecasts – a T&D upgrade may never be needed.
- **Sufficient lead time is critical.** It is necessary to allow for sufficient planning, for sufficient deployment of efficiency resources to meet needs (particularly for larger projects) and for refinement of efficiency strategies during the deployment process.
- **Smaller is easier.** The smaller the area being addressed, the easier it is to consider efficiency and other non-wires alternatives. It is easier to characterize the opportunity in small areas. Also, savings will need to be acquired from fewer customers. Both of those things mean shorter lead times will be required.
- **Distribution is easier than transmission.** Distribution deferral projects will be smaller in scope. They are also less technically complex, involve fewer parties, and do not involve ISOs/RTOs and associated regional cost allocation frameworks (i.e. cost socialization issues).
- **Cross-discipline communications is critical.** Collaboration between efficiency program managers and T&D planners is critical to considering deploying efficiency as an alternative to T&D investments. Both have much to learn from each other. Some level of trust must be developed between the two groups.
- **Efficiency should be integrated with other distributed resources.** Although efficiency programs can sometimes be sufficient to defer T&D investments, they will often need to be deployed in concert with demand response, distributed generation and other resources to enable deferment of T&D investments (particularly for larger projects).

## Recommendations

The potential economic and other benefits of efficiency programs as a T&D resource are largely being ignored today. Some fundamental policy changes are required if that is to change:

- **Require least-cost T&D planning.** Experience in several jurisdictions suggest this is essential (though not sufficient) to beginning serious consideration of efficiency and other non-wires alternatives.
- **Require consideration of integrated solutions.** To ensure that potential synergies between efficiency and other non-wires alternatives are considered, any requirement for least cost-planning should make clear that all options, including different combinations of distributed resources, should be considered.
- **Institutionalize a long-term planning horizon.** The longer the lead time, the more likely it will be that efficiency and/or other distributed resources could cost-effectively defer T&D investments. At a minimum, T&D needs should be forecast at least 10 years into the future.
- **"Level the playing field" in payment for wires and non-wires alternatives.** Cost-allocation frameworks that socialize costs for transmission projects across a region but require all the cost of non-wires alternatives to be born locally create enormous disincentives to pursue least cost solutions.
- **Collect more data on efficiency's impacts.** In much of the country, relatively little data on the hourly and seasonal impacts of efficiency resources has been collected and made public over the past two decades. Better data should help address concerns of T&D system planners.
- **Start with pilot projects.** Pilots offer important, lower risk opportunities to bring together efficiency program and T&D planners.
- **Leverage "smart grid" investments.** Customer and end-use data collected through such systems may enable better assessments of the potential for efficiency to serve as a T&D resource.

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# 1. Introduction

Improvements to electric efficiency in homes and businesses provide a variety of benefits to both the customers making the improvements and the electric system as a whole.[1] The most widely recognized are annual energy savings and system peak demand savings. Most consumers are primarily interested in energy savings because they typically drive cost savings on electricity bills. Utilities and grid operators are often most interested in reductions in load at the time of system peak, which enable them to avoid purchasing expensive peak generating capacity. A much less commonly recognized or valued benefit of efficiency investments is the potential for cost-effectively deferring upgrades to transmission and distribution (T&D) systems.

This paper focuses on that potential. In particular, it summarizes US experience to date and lessons learned from initiatives in which geographically targeted efficiency programs have played a major role in electric utility funded efforts to defer transmission and/or distribution system investments. Although other demand resources such as demand response and distributed generation can also be considered viable alternatives to T&D investments and have occasionally been deployed for that purpose, this paper does not explore those options in any detail, except when they are deployed as part of a multi-pronged strategy in conjunction with geographically targeted efficiency programs.

## Context – Historic and Future Investments in Transmission and Distribution

The potential to defer upgrades to T&D warrants much more serious consideration than it has historically been given. As Figure 1 shows, T&D investments by investor-owned utilities, which collectively account for approximately two thirds of electricity sales in the United States, have averaged about $26 billion annually over the past decade.

If public utilities are investing in T&D at the same rate, then total T&D investment nationally would be on the order of $40 billion per year. That level of investment is expected to continue, if not increase, in the future. Indeed, as Figure 2 illustrates, the Edison Electric Institute recently commissioned a study that concluded the US power sector, including both investor-owned and public utilities, will require over $1.5 trillion in capital investments

***Figure 1***[2]

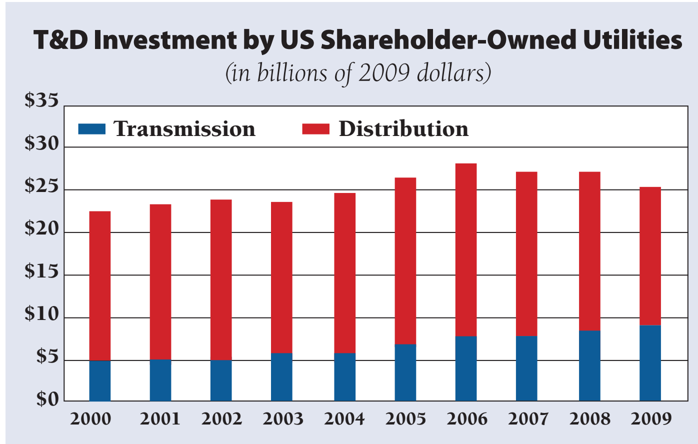
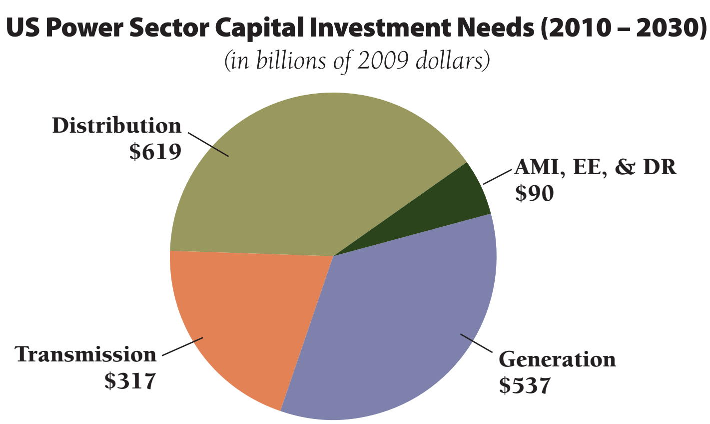



***Figure 2***[3]




1 There are also often a number of non-energy benefits (e.g., improved comfort, water and/or other resource savings, reduced operation and maintenance costs, increased productivity) that we do not address in this paper.

2 Personal communication with Steve Frauenheim, Edison Electric Institute (EEI), August 5, 2011. Data are from EEI's Statistical Yearbook of the Electric Power Industry 2009 Data, Table 9.1.

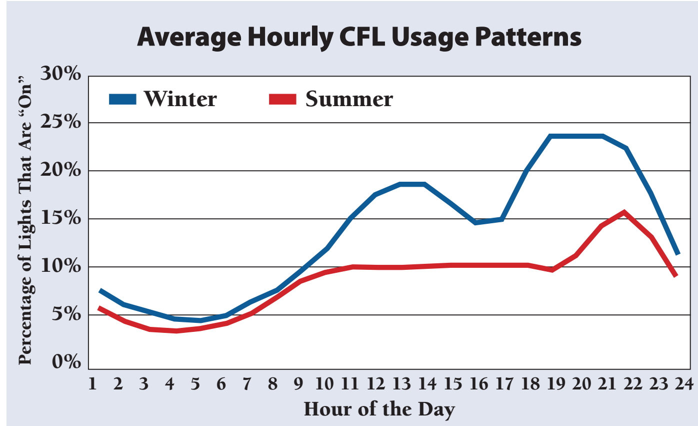
between 2010 and 2030 (2009 dollars), and that 40% of that investment – more than $600 billion (i.e., more than $30 billion/year) – will be in distribution system infrastructure and another 20% – more than $300 billion (i.e., more than $15 billion/year) – will be in transmission system infrastructure. Only about one third of the forecast investment is in new generation; another 6% is in advanced metering infrastructure, energy efficiency, and demand response.

## "Passive Deferral" vs. "Active Deferral"

Deferrals of T&D investments can take two forms: passive deferral and active deferral. Passive deferral occurs when the growth in load or stress on feeders, substations, transmission lines, or other elements of the T&D system is reduced as a result of broad-based (e.g., statewide or utility service territory-wide) efficiency programs. For example, a statewide program to promote the sale and purchase of compact fluorescent light bulbs (CFLs) will have the effect of lowering loads on every element of the T&D system every hour of the day. To be sure, the amount of load reduction from such a program will vary considerably depending on the season (more during winter than summer), hour of the day (e.g., more during the evening than the day), and the customer mix served (e.g., more for feeders, substations, etc. serving primarily residential customers). As Figure 3 shows, however, the load shape of residential lighting is such that – across a population of program participants – some reductions in energy use will occur every hour of the year. Some reductions thus will occur during every hour of peak demand for every element of the T&D system.

Passive deferral benefits are sometimes reflected in average statewide or utility service territory-wide avoided T&D costs. Such avoided costs – along with avoided costs

*Figure 3*[4]




of energy and system peak capacity – are commonly used to assess whether efficiency programs are cost-effective (usually a regulatory requirement for funding approval). At the most general level, estimates of avoided T&D costs are typically developed by dividing the portion of forecast T&D capital investments that are associated with load growth (i.e., excluding the portion that is associated with replacement due to time-related deterioration or other factors that are independent of load) by the forecast growth in system load. Such estimates can vary considerably, often as a function of the utilities' assumptions regarding how much investment is deferrable. For example, in New England, utility estimates of avoided T&D costs typically have ranged from about $55 per kW-year to $120 per kW-year.[5] Avoided distribution costs typically account for 70% to 80% of those values (i.e., avoided distribution costs are typically two to four times greater than avoided transmission costs). Estimates for several utilities in California and the Pacific Northwest have ranged from $30 to $105 per kW-year, with an average of close to $50.[6] Again, avoided distribution costs are the larger

3 Chupka, Marc et al, (The Brattle Group). *Transforming America's Power Industry: The Investment Challenge 2010-2030*, prepared for the Edison Foundation, November 2008. The forecast presented here is for the report's base case scenario, including "realistically achievable potential" for energy efficiency and demand response. The report's 2006 costs were increased by 6.4% so that they could be presented in 2009 dollars (based on changes in the Consumer Price Index between 2006 and 2009).

4 Nexus Market Research, *Residential Lighting Markdown Impact Evaluation,* submitted to Markdown and Buydown Program Sponsors in Connecticut, Massachusetts, Rhode Island, and Vermont, January 20, 2009 (from Figures 5-1 and 5-2).

5 Most are in the range of $55 to $85 (Synapse Energy Economics, *Avoided Energy Supply Costs in New England: 2009 Report,* revised October 23, 2009, p. 6-66). Vermont's, however, is approximately $120 per kW-year for summer peak savings and $80 per kW-year for winter peak savings (personal communication with Erik Brown, Efficiency Vermont, December 23, 2011).

6 Northwest Power and Conservation Council, Sixth Northwest Conservation and Electric Power Plan, February 2010 (http://www.nwcouncil.org/energy/powerplan/6/final/SixthPowerPlan_Appendix_E.pdf), p. E-14.

of the two components – on the order of twice as large as avoided transmission costs.[7] At the other extreme, in some jurisdictions it is conservatively assumed that no T&D investments can be avoided.[8]

Active deferral of T&D investments can occur when a conscious decision is made to invest in energy efficiency measures or programs – in targeted geographic locations – for the specific purpose of lowering loads on local T&D system elements. This concept has been actively pursued in relatively few jurisdictions to date. A variety of factors likely contribute to its limited testing for both transmission and distribution needs:

- **Economic incentives.** Utilities typically earn rates of return on capital investments. In many jurisdictions they do not make money on investments in efficiency.[9]

- **Efficiency's multiple attributes/benefits.** Efficiency resources provide a variety of benefits, including energy savings, peak capacity savings, environmental emission reductions, and T&D reliability improvements. Properly assessing whether efficiency could be a cost-effective alternative to T&D investments requires accounting for all of those benefits (e.g., although efficiency may not be cost-effective when considering just its T&D reliability benefits, it may be when considering all its benefits). That requires a holistic, systemic perspective that has not been universally adopted by utilities or their regulators, however, and is generally not a concern of ISOs/RTOs.

- **System planning is highly technical.** The technical specialization needed to do T&D planning fosters an environment biased to technical solutions. Put another way, utilities and ISOs/RTOs tend to be engineering oriented, with a propensity toward building capacity to meet growing consumer demand.

- **System engineers distrust of demand-side resources.** System engineers trust assets that they can control, like "poles and wires," and tend to be more skeptical or distrustful of investments on the customer side of the meter to reduce demand.

- **Risk aversion.** Related to the point above, utilities (like many other businesses) are often reluctant to try something different, particularly if they perceive any regulatory risk from doing so.

In general, the barriers to deployment of non-wires solutions to transmission needs are greater than those for distribution system needs. To begin with, transmission needs are typically more technically complex. In addition, the magnitude of the demand resources needed to defer them are larger and spread across much larger populations of customers. That can enhance system planners' fear of the ability of demand resources to meet reliability needs. It also typically means that longer lead times for consideration of non-wires solutions are necessary. Two additional factors are also critically important.

- **Socialization of transmission investments, but not non-wires alternatives.** The costs of transmission investments are often socialized regionally (i.e., across the entire grid), whereas the costs of efficiency programs or other non-wires solutions must typically be borne entirely by the local utility and its customers. This creates a classic "tragedy of the commons" in which it is less expensive for the local utility to choose what is often the most expensive option for a region.

7 Ibid. Figures E-5 (avoided transmission costs) and E-6 (avoided distribution costs) each provide eight separate examples. Only three of those examples are common, however: PG&E, Pacificorp and PGE. For those three utilities, avoided distribution cost estimates were roughly double avoided transmission cost estimates.

8 For example, see: Consumers Energy, *2012-2015 Amended Energy Optimization Plan*, submitted to the Michigan Public Service Commission, Case No. U-16670, August 1, 2011, p. 25.

9 A recent ACEEE study identified 18 states that had a mechanism that allowed investor-owned utilities to earn shareholder incentives for good performance in administering efficiency programs (Hayes, Sara et al, *Carrots for Utilities: Providing Financial Returns for Utility Investments in Energy Efficiency,* ACEEE Report Number U111, January 2011).

- **Diffusion of responsibility for transmission planning and decision-making.** State regulators, utilities, ISOs/RTOs, and ultimately FERC all have roles in transmission planning and approval of transmission investments. It is difficult for a new approach (i.e., non-wires solutions) to get traction when there is no one entity "in charge" that can require consideration of such approaches. It is unclear how the recent FERC Order 1000, which requires ISOs/RTOs to consider state policies in their decisions, will change things.

Despite these barriers, aggressive geographically targeted energy efficiency programs have been implemented in several jurisdictions in an attempt to defer specific T&D projects. The purpose of this paper is to document the lessons learned from those efforts. Again, although there are a variety of potential non-wires alternatives that can be and have been deployed to defer T&D investments, the focus of this paper is only on those projects in which energy efficiency played or is playing a substantial role. It is also important to note that this paper documents the consideration of efficiency as a T&D resource as of late 2011. Several of the cases described below are still evolving, potentially in ways that could add significantly to information and ideas presented herein.

# 2. Active Deferral of T&D Investment – Selected Examples

## A. Early History

The concept of using geographically targeted energy efficiency investments to cost-effectively defer T&D system upgrades is not a new one. One can find numerous papers on the concept in efficiency conference proceedings going back to at least the early 1990s. The Electric Power Research Institute (EPRI), a research organization serving the utility industry, began pursuing several projects to assess the potential for integrating demand-side management (DSM) into utility T&D planning during the same time period. Most important, several groundbreaking projects were undertaken in the 1990s to test the concept. What follows are brief descriptions of those projects.

### Pacific Gas and Electric (California) – Delta Project

One of the most widely publicized of these early projects was the Pacific Gas and Electric (PG&E) Model Energy Communities Program, commonly known as the Delta Project, which ran from July 1991 through March 1993. Its purpose was to determine whether the need for a new substation that would otherwise be required to serve a growing "bedroom community" of 25,000 homes and 3,000 businesses in far eastern Contra Costa County, California could be deferred through intensive efficiency investments. Peak demand in this area occurred on summer weekdays between 7 pm and 8 pm – much later than PG&E's system peak (typically between 3 pm and 5 pm). This later local peak was driven by the fact that 74% of the peak load was residential, with many of the residential customers being two-income families who had long commutes from the San Francisco and Oakland areas and turned on their air conditioners when arriving home to 100° F heat.[10]

As a result, the largest portion of the project's savings was projected to come from a residential retrofit program targeted to homes with central air conditioning (the vast majority of homes in the targeted area). Under the initial design, participating homes would receive free installation of low-cost efficiency measures (e.g., CFLs, low flow showerheads, water heater blankets) during an initial site visit and would be scheduled for follow-up work with major measures such as duct sealing, air sealing, insulation, sun screening, and air conditioner tune-ups. More than 2,700 homes received such major measures. Later the program changed its focus to promoting early replacement of older, often over-sized and inefficient central air conditioners with new, efficient models. Other components of the Delta Project included commercial retrofits, a residential new construction program, and a small commercial new construction program.

Evaluations suggested that the project produced 2.3 MW of peak demand savings. The savings did come at a high cost – roughly $3,900 per kW. This can likely be attributed to a couple of key factors. First, the project had an extremely compressed timeframe. It was planned and launched within six months; the implementation phase was less than two years. A second related factor was that some of the efficiency strategies produced much lower levels of savings than initially estimated, whereas others produced more. Because of the compressed timeframe for the project, the switch in emphasis to the better performing program strategies could not occur early enough to keep total costs per kW at more reasonable levels. For example, the residential shell and duct repair efforts were initially projected to generate nearly 1.8 MW of peak demand savings, but in the end, produced only about 0.2 MW at a cost of over $16,000 per kW. In contrast, the early replacement residential central air conditioners produced 1.0 MW of peak savings – about 2.5 times the original forecast of about 0.4 MW – at a cost of about $900 per kW.

10 The Results Center, "Pacific Gas & Electric Model Energy Communities Program," Profile 81, 1994.

The final evaluation of the project suggested that the savings achieved succeeded in deferring the need for the substation for at least two years.[11] Although the project suggested that geographically targeted DSM could potentially defer T&D investments, no projects of this kind appear to have been pursued in California since.

## Portland General Electric (Oregon) – Downtown Portland Pilot

In 1992, Portland General Electric (PGE) began planning the launch of a pilot initiative to assess the potential for using DSM to cost-effectively defer distribution system upgrades; implementation began in early 1993.[12] The pilot focused on several opportunities for deferring both transformer upgrades planned for large commercial buildings and grid network system upgrades planned for downtown Portland, Oregon. The projects were identified from a review of PGE's 5-year transmission and distribution plan. Although the PGE system was winter-peaking, downtown Portland was summer-peaking, so the focus would be on efficiency measures that reduced cooling and other summer peak loads. To be successful, deferrals would need to be achieved in one to three years, with the lead time varying by project. In each case, the value of deferring the capital improvements was estimated. The estimates varied by area, but averaged about $35 per kW-year.[13]

Two different strategies were pursued. In the case of the individual commercial buildings, where peak demand reductions of several hundred kW per building were needed to defer transformer upgrades, the utility relied on existing system-wide DSM programs, but target marketed the programs to the owners of the buildings of interest using sales staff that already had relationships with the building owner or property management firm. For the grid network system objectives, where peak reductions of 10% to 20% for entire 10- to 15-block areas were needed, the utility contracted with energy service companies (ESCOs) to deliver savings. The ESCO contracts had two-tier pricing structures designed to encourage comprehensive treatment of efficiency opportunities and deep levels of savings. The first tier addressed savings up to 20% of a building's electricity consumption. The second tier was a much higher price for savings beyond 20%.[14]

The results of the pilot were mixed. For example, savings in one of the targeted commercial buildings was nearly twice what was needed, deferring and possibly permanently eliminating the need for a $250,000 upgrade. Savings for another building, however, fell short of the amount of reduction needed to defer its transformer upgrade. While other options were being explored to bridge the gap, an unexpected conversion from gas to electric cooling of the building "eliminated any opportunity to defer the upgrade."[15] The results for the first grid area network targeted were also very instructive. Of the 100 accounts in the area, the largest 20 accounted for more than three quarters of the load. By ultimately treating 12 of those 20, the ESCOs contracted by PGE actually succeeded in reducing load through efficiency measures by nearly 25% in just one year. That was substantially more than the 20% estimated to be necessary to defer the need for a distribution system upgrade. The utility's distribution engineering staff decided to proceed with construction of the upgrade before the magnitude of the achieved savings was known, however, because they did not have sufficient confidence that the savings would be achieved and would be reliable and persistent. It is also worth noting that the utility's marketing staff who were managing the ESCO's work were not even made aware of the decision to proceed with the construction until after it had begun – a telling indication of the lack of communication and trust between those responsible for energy efficiency initiatives and those responsible for distribution system planning.[16]

Despite some notable successes with its pilot, PGE has not subsequently pursued any additional efforts to defer distribution system upgrades through energy efficiency.[17]

11 Pacific Gas and Electric Company Market Department, *Evaluation Report: Model Energy Communities Program, Delta Project 1991-1994*, July 1994.

12 Personal communication with Rick Weijo, Portland General Electric, August 10, 2011.

13 Weijo, Richard O. and Linda Ecker (Portland General Electric), "Acquiring T&D Benefits from DSM: A Utility Case Study," Proceedings of 1994 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 2.

14 Ibid.

15 Ibid.

16 Ibid.

17 Personal communication with Rick Weijo, Portland General Electric, August 10, 2011.

## Bonneville Power Administration

In the early 1990s, the Puget Sound area received more than three quarters of peak energy (i.e., during times of high demand for electric heat) via high voltage transmission lines that crossed the Cascade mountain range. Bonneville Power Administration (BPA) studies concluded the region could experience a voltage collapse – or blackout or brownout – if one of the lines failed during a cold snap.[18] The level of risk "violated transmission planning standards."[19]

The traditional option for addressing this reliability concern would have been to build additional high voltage transmission lines over the Cascades into the Puget Sound area. BPA and the local utilities chose instead, however, to pursue a lower cost path that included adding voltage support to the transmission system (e.g., "series capacitors to avoid building additional transmission corridors over the Cascades") and more intensive deployment of energy efficiency programs (focused on loads that would help avoid voltage collapse). The voltage support was by far the most important of these elements.[20] The project, known as the Puget Sound Area Electric Reliability Plan, ended up delaying construction of expensive new high voltage transmission lines for at least a decade.[21] Indeed, no new cross-Cascade transmission lines have been built to date.[22]

As discussed further below, BPA has not yet pursued an additional project to defer transmission system investments with efficiency programs.[23] It has, however, institutionalized a process for assessing whether non-transmission alternatives, including efficiency, would be preferable and, for the past decade or so, has initiated that process on several occasions (the most recent just getting started in the spring of 2011).

## Green Mountain Power (Vermont) – Mad River Valley

In 1995, Green Mountain Power (GMP), Vermont's second largest investor-owned electric utility, launched an initiative – the first of its kind in the state – to defer the need for a new distribution line in the Mad River Valley – a region in the central part of the state made famous by the Sugarbush and Mad River ski resorts. The existing U-shaped 34.5-kV line serving the valley had a reliable capacity of 30 MW. Sugarbush, which was located at the base of the "U" (its weakest point) and was already the largest load on the line, had announced plans to add up to 15 MW of load associated with a new hotel, a new conference center, and additional snow-making equipment. The existing line could not accommodate that kind of increase. Studies suggested that a new parallel 34.5-kV line would need to be added at a cost of at least $5 million. Sugarbush initially requested that GMP

18 US Department of Energy, Bonneville Power Administration, Public Utility District Number 1 of Snohomish County, Puget Sound Power & Light, Seattle City Light and Tacoma City Light, "Puget Sound Reinforcement Project: Planning for Peak Power Needs," Scoping report, Part A, Summary of Public Comments, July 1990.

19 Bonneville Power Administration Non-Construction Alternatives Roundtable, "Who Funds? Who Implements?" Subcommitee, "Non-Construction Alternatives – A Cost-Effective Way to Avoid, Defer or Reduce Transmission System Investments," March 2004.

20 Indeed, although the plan included additional investments in efficiency, the additional capacitors, coupled with the addition of some local combustion turbines, were likely enough to defer the transmission lines even without the additional efficiency investments (personal communication with Frank Brown, BPA, 11/7/11).

21 Bonneville Power Authority, "Non-Wires Solutions Questions & Answers" fact sheet.

22 The system has been significantly altered over the past two decades as a result of substantial fuel-switching from electric heat to gas heat, the addition of significant wind generating capacity (much of it for sale to California), and other factors. At least until recently, BPA thus has had more "North-South issues" than "East-West issues" (personal communication with Frank Brown, BPA, 11/7/11). That may change in the future as utilities begin to rely more on wind generators east of the cascades (personal communication with Joshua Binus, BPA, 12/12/11).

23 In the mid to late 1990s, however, it did invest substantially in a demand response initiative in the San Juan islands to address reliability concerns after the newest of three underwater cables bringing power to the islands was accidentally severed. The initiative ran for five years and succeeded in keeping loads on the remaining cables at appropriate levels until a new cable was added.

pay for the new line. GMP was hesitant to do so, however, and Vermont's line extension rules were such that the utility and others could legitimately argue that much of the cost should be directly imposed on Sugarbush (and therefore less on other ratepayers).[24] Ensuing negotiations between GMP, Sugarbush, and the state's rate-payer advocate ultimately led to an alternative solution:

1. Sugarbush would ensure that load on the distribution line – *not just its load, but the total load of all customers* – would not exceed the safe 30 MW level;[25] and
2. GMP would invest in an aggressive effort to promote investment in energy efficiency among all residential and business customers in the region.[26]

To meet its end of the bargain, GMP filed and regulators approved the following four efficiency programs targeted to the Mad River Valley:

- Large commercial/industrial retrofit program (targeting the 10 largest customers in the valley);
- Small commercial/industrial retrofit program;
- Residential retrofit program, focusing particularly on homes with electric heat and hot water (promoting both fuel-switching and weatherization); and
- Residential new construction assessment fee program, which imposed a mandatory fee on all new homes being constructed in the valley to pay for a home energy rating and offered both repayment of the fee and an additional incentive for building the home efficiently.[27]

A couple of these programs were largely the same as programs GMP was offering to customers across its entire service territory, except that they were more aggressively marketed to Mad River Valley customers. In 1996, the year during which most of the project activity took place, GMP's efficiency program spending on the Mad River Valley represented about one quarter of its total DSM spending,[28] despite the fact that the area served represented no more than about 5% of its sales base.[29]

By the time the targeted efforts were concluded in early 1997, roughly half of the target populations had participated in the small commercial and industrial (C&I) retrofit and residential retrofit programs, and 7 of the 10 customers targeted by the large retrofit program had participated. Further, three of the four programs had achieved their savings goals. The large C&I retrofit program was the one exception, having achieved only about 20% of the forecasted savings (suggesting that the depth of savings achieved per participant was much lower than projected). Because that program represented less than one fifth of the total savings projected for the Mad River Valley project, however, the project as a whole came close to achieving its overall savings goal.

This project was initially touted as "the first of many" designed to address T&D constraints.[30] As discussed further below, it took more than a decade for that vision to begin to be realized. Nevertheless, it was an important stepping stone in the process of distributed utility planning in Vermont.

24 Cowart, Richard et al., "Distributed Resources and Electric System Reliability, Regulatory Assistance Project, September 2001. Available: http://www.raponline.org/document/download/id/682.

25 This was possible because Sugarbush was such a large portion of the load on the line. It subsequently installed a real-time meter to monitor the consumptions of its own operations and telemetry to monitor total load from all customers at the local substation. It used this information to manage its own operations, including the timing of its snow-making, to keep total loads on the substation below 30 MW. In addition to avoiding any costs associated with its responsibility for the need to upgrade the power line, Sugarbush also received a rate discount from GMP. (Ibid.)

26 Ibid.

27 Green Mountain Power Corporation, "Demand Side Management Program Filing," April 28, 1995 (Revised 5/5/95).

28 Green Mountain Power Corporation, "Demand Side Management Programs 1996 Annual Report," April 1, 1997.

29 Personal communication with Dave Grimason, former GMP efficiency program manager, November 7, 2011.

30 Green Mountain Power Corporation, "Demand Side Management Program Filing," April 28, 1995 (Revised 5/5/95), Executive Summary p. 2.

## B. More Recent Developments

In the past several years, several additional efforts to defer T&D system investments have been undertaken. In a couple of additional jurisdictions, processes have been put in place to require that efficiency and other demand resources be considered as alternatives.

### Consolidated Edison (New York City)

Consolidated Edison (Con Ed), the electric utility serving New York City and neighboring Westchester County, has been perhaps the most aggressive in the United States in integrating end-use energy efficiency into T&D planning. That integration has occurred on two levels.

First, as part of the annual development of its 10-year "load relief plan" (in which it forecasts any shortfalls in transmission, sub-transmission, and area substation capacity and establishes plans for addressing those shortfalls), the Company now routinely estimates the effects of system-wide efficiency programs on the individual peak demands of each of its 91 distribution networks and load areas, adjusting for the geographic variability in the market penetration of different efficiency programs, the load profiles of different efficiency programs, and the load profiles (and peak periods) of each distribution network. The company recently estimated that "including demand-side management in the 10-year forecast reduced projected capital expenditures by more than $1 billion."[31]

Second, Con Ed routinely assesses whether additional, geographically targeted investments in demand resources could cost-effectively defer investments in its distribution system. More important, where analysis suggests such cost-effective deferrals are possible, the utility invests in, closely tracks, and carefully evaluates the impacts of those resources. When Con Ed assesses cost-effectiveness, it considers all the benefits of efficiency investments, not just the T&D benefits (i.e., it compares the net present value of energy savings, system peak capacity savings, and T&D deferral benefits to the costs of the efficiency programs).

This geographically targeted investment in efficiency began in 2003, when growth in demand was causing a number of Con Ed's distribution networks to approach their peak capacity. Given the density of its customer base, much of the company's system is underground, making upgrades expensive and disruptive. The Company thus began to assess whether it would be feasible and cost-effective to defer such upgrades through locally targeted end-use efficiency, distributed generation, fuel-switching, and other demand-side investments. At least initially, the focus was on projects "with need dates that were up to five years out and… required load relief that totaled less than 3% to 4% of the predicted network load."[32] A decision was made to proceed with geographically targeted demand resource investments, however, whenever it was determined that such investments were likely to be both feasible and cost-effective.

To maximize the financial benefits of relying on demand resources, Con Ed has chosen "not to hedge its bets by continuing the T&D planning and implementation process" in parallel with its pursuit of alternative demand resources. Instead, the Company has chosen to contract out the acquisition of demand resources to ESCOs and – to address reliability risks – to include in those contracts both "significant upfront security and downstream liquidated damage provisions," as well as rigorous measurement and verification requirements. Contract prices are established through a competitive bidding process, with the Company's analysis of the economics of deferment being used to establish the highest price it would be willing to pay for demand resources. Those threshold prices have varied from network to network. When the amount of demand resources bid at prices below the cost-effectiveness threshold were insufficient to defer T&D upgrades, supply-side improvements have been pursued instead.

In its initial pilot phase, the Company established contracts with three ESCOs to provide load reductions in nine networks areas: five in midtown Manhattan, three in Brooklyn, and one in The Bronx. In subsequent phases, four different ESCOs were contracted to deliver load reductions in 21 additional network areas: 13 in Manhattan, four on Staten

31 Gazze, Chris and Madlen Massarlian, "Planning for Efficiency: Forecasting the Geographic Distribution of Demand Reductions," in *Public Utilities Fortnightly,* August 2011, pp. 36-41.

32 Gazze, Chris, Steven Mysholowsky, Rebecca Craft, and Bruce Appelbaum. "Con Edison's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction," in Proceedings of the ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 117-129.

Island, and four in Westchester County. Although ESCOs were allowed to bid virtually any kind of permanent load reduction, all of the accepted bids to date have been solely for the installation of efficiency measures. There have been a couple of explorations of distributed generation, but they have not yet been shown to be cost-effective.[33] All told, between 2003 and 2010, the Company employed geographically targeted efficiency programs to defer T&D system upgrades in more than one third of its distribution networks.

This approach has had considerable, but not universal, success. As Figure 4 shows, in aggregate the level of peak load reduction for Phase 1, which ran through 2007, was approximately 40 MW – or 7 MW less than the contracted level. As a result, Con Ed collected considerable liquated damages from participating ESCOs. Load reductions in subsequent phases have been close to those contracted in aggregate. Those aggregate results mask some differences across network areas, however. In particular, reductions in areas dominated by residential loads with evening peaks were achieved ahead of schedule, whereas reductions in areas whose loads were dominated by commercial customers with mid-day peaks have lagged behind goals. On the other hand, much of that commercial sector savings shortfall appears attributable to the recent economic recession, which also had the effect of dampening baseline demand, offsetting most of the efficiency program shortfalls.[34] As shown in Figure 5, even when there was a shortfall relative to the savings target for the largest of the T&D deferral projects Con Ed undertook in Phase 1 – the Astor Substation deferral project – the efficiency investments still produced substantial economic benefits ($28 million, or about $1,950 per kW of savings) that were very cost-effective (benefit-cost ratio of 3:1).[35]

This highlights an important benefit of efficiency programs – they are often load-following. Put another way,

***Figure 5*** [37]

**Summary of Results for Astor Substation**

**Project:** Build new substation to relieve five adjacent networks
**Cost:** $85 million (original estimate)
$145 million (as built)
**Deferral:** 2007 to 2009

| Shortfall | 2005 | 2006 | 2007 | 2008 |
|---|---|---|---|---|
| Shortfall (Incremental) | 0 | 2 | 9 | 8 |
| Contracted (Cumulative) | 0 | 4 | 13 | 21 |
| Delivered (Cumulative) | 1 | 4 | 8 | 14 |

**RFP:** Jun 2003
**Contract:** Sep 2004 – Jan 2005
**Savings:** $28 million (~ $1,950/kW)
**TRC:** 3.1
**Note:** Load growth was slower than forecast, offsetting under delivery

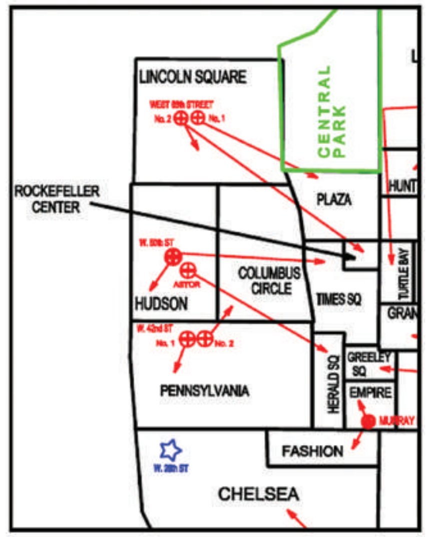
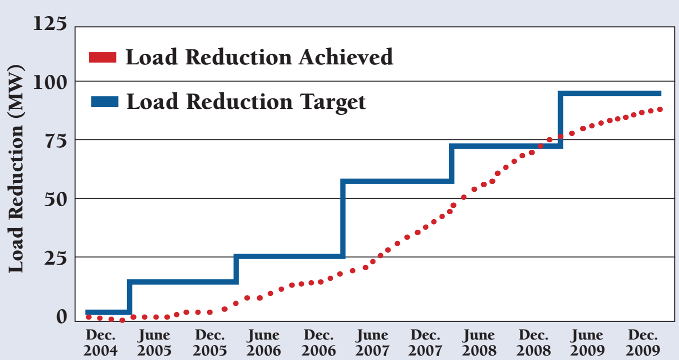



***Figure 4*** [36]

**Con Ed's T&D Savings Compared to Goals**




33 Although all types of demand resources have been considered, only energy efficiency has been pursued to date, because it is the only demand resource proven to be cost-effective (personal communication with Chris Gazze, February 2011).

34 Gazze, Mysholowsky, and Craft (2010).

35 Gazze, Chris (Con Ed) and Bruce Appelbaum (ICF), "Con Edison's Targeted DSM Program," presentation at ACEEE Summer Study on Energy Efficiency in Buildings, August 18, 2010, Pacific Grove, CA.

36 Graph reproduced from Gazze, Mysholowsky, Craft, and Appelbaum (2010) with permission from Con Ed.

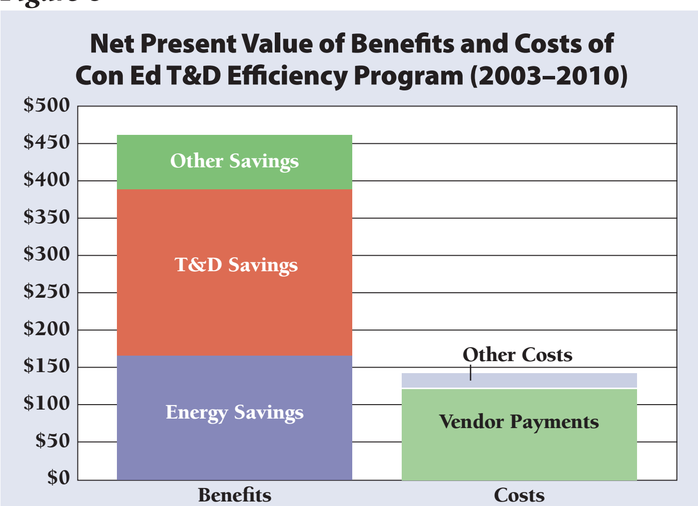
37 Graphic from Gazze and Appelbaum presentation, used with permission from Chris Gazze.

participation in efficiency programs tends to increase when load is growing more quickly and decrease when load is not growing quickly. In that sense, efficiency programs can help mitigate risk associated with forecast uncertainties. As Con Ed put it:

> *"…using DSM to defer projects bought time for demand uncertainty to resolve, leading to better capital decision making. Moreover, widespread policy and cultural shifts favoring energy efficiency may further defer some projects to the point where they are never needed…In fact, Con Edison has projected that in the absence of this program it would have installed up to $85 million in capacity extensions that may never be needed."*[38]

As Figure 6 shows, in aggregate, Con Ed has saved more than $75 million when comparing the full costs of the efficiency programs to just the T&D costs that were

***Figure 6*** [39]




avoided. When other efficiency benefits (e.g., energy savings and system peak capacity savings) are also considered, the efficiency investments have saved Con Ed and its customers more than $300 million.

## Efficiency Vermont Geo-Targeted DSM

Shortly after the Mad River Valley project (see discussion earlier) was completed, negotiations began within the state to shift responsibility for efficiency program administration from the utilities to a dedicated "efficiency utility" – eventually to be named "Efficiency Vermont" – that would be selected through a competitive bidding process. The settlement agreement and subsequent September 1999 Public Service Board (the Board) order that created Efficiency Vermont made clear that, although Efficiency Vermont would be responsible for statewide efficiency programs, the utilities would still be responsible for funding and implementing any additional efficiency that could be justified as cost-effective alternatives to T&D system upgrades (although they could contract implementation to Efficiency Vermont). The Board also agreed to "initiate a collaborative process to establish guidelines for distributed utility planning."[40] That collaborative culminated in a set of guidelines approved by the Board in 2003,[41] as well as the creation of a number of "area specific collaboratives" in which opportunities for deferring specific T&D upgrades through non-wires alternatives would be explored. None of those discussions led to implementation of any such alternatives, however.

At roughly the same time (i.e., 2003), VELCO, the state's transmission utility, formally proposed a very controversial large project to upgrade transmission lines from West Rutland to South Burlington (known as the Northwest Reliability Project). As required by Vermont law, VELCO filed an analysis of non-transmission alternatives. In all, five different combinations of alternatives were analyzed – four combinations of different kinds of local generation and a fifth combination of local generation and aggressive DSM. The analysis suggested that the four generation-only options were more expensive than the transmission line, but that the fifth option including DSM had a lower societal cost than the transmission line.[42] That option, however, would involve much larger capital expenditures than the transmission line. Further, whereas much of the cost of the transmission option would be socialized across the New England Power Pool (Vermont pays a very small share of the portion of costs that are socialized across the region), the cost of the alternative path would be borne entirely by Vermont ratepayers due

38 Gazze, Mysholowsky, and Craft (2010).

39 Cost and benefit data provided by Chris Gazze, February 11, 2011. Note that "other costs" includes program administration ($2.9 million), M&V ($9.2 million), and customer costs ($9.9 million).

40 State of Vermont, Public Service Board Order, Docket No. 5980, pp. 54-58.

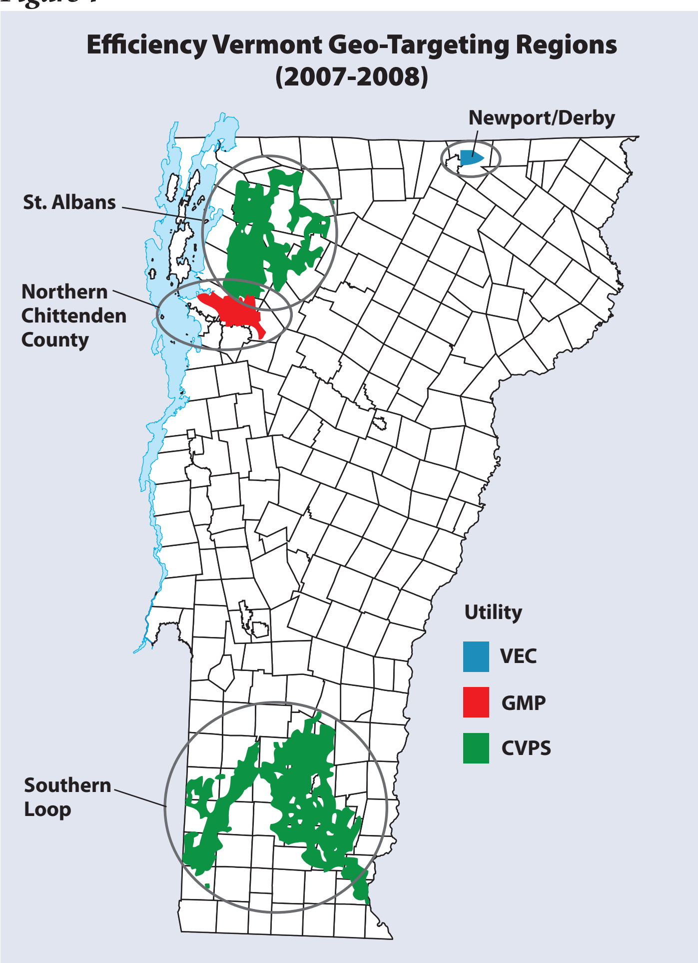
41 State of Vermont, Public Service Board Order, Docket No. 6290.

42 La Capra Associates, "Alternatives to VELCO's Northwest Reliability Project," January 29, 2003.

to New England ISO rules. Those concerns, coupled with VELCO's concerns that the level of DSM envisioned would be unprecedented, led the utility to argue in favor of the transmission option.[43] The Board ultimately approved VELCO's proposal in early 2005, but expressed concern and frustration with VELCO's planning process, namely that it did not consider alternatives, particularly efficiency, early enough in the process to make them truly viable options.[44]

The approval of the transmission line contributed to the passage later that year of legislation (Act 61) that eliminated the statutory spending cap for Efficiency Vermont, instructed the Board to determine the optimal level of efficiency spending, and made clear that cost-effectively deferring T&D upgrades should be one of the objectives the Board considers in establishing the budget. The Board subsequently increased Efficiency Vermont's budget by about $6.5 million (37%) in 2007 and $12.2 million (66%) in 2008 and ordered that all of the additional spending be focused on four geographically targeted areas: northern Chittenden County, Newport, St. Albans, and the "southern loop" (see Figure 7).[45] Those areas had been identified by the state's utilities as areas in which there may be potential for deferring significant T&D investment. Collectively, these efforts became known as Efficiency Vermont's "geo-targeting" initiative.[46]

*Figure 7* [47]




As Table 1 shows, these areas were fairly diverse in terms of the density of population, the geographic area they cover, the relative importance of residential vs. commercial and industrial loads, and the number of large customers. Two of the areas were summer peaking, one was winter peaking, and one had similar summer and winter peaks. The peak loads in the area varied from 18 to 70 MW in 2007. Forecasted load growth without efficiency programs ranged from 1.7% to 4.3% per year. Collectively, the four areas contained 63,000 customers – or 18% of the state's customer base. A total of 167 were large users (greater than 500 MWh of annual consumption), 8,600 were other business customers (many of them quite small), and about 54,000 were residential customers.[48]

It is important to note that the investment in geo-targeting was viewed by the Board, utilities, and Efficiency Vermont as a "proof of concept" experiment. The selection of the targeted areas was rushed and probably not as well vetted as necessary to ensure deferral potential. Indeed, savings targets were not established from an analysis of how much was needed to defer the capital investments. Rather, they were set based on what was estimated to be achievable given available budget resources.

The original 18-month savings targets (from mid-2007 through the end of 2008) were 7.2 MW of summer peak savings (across the three areas with summer peaks) and 7.7

43 Ibid.

44 Vermont Public Service Board, "Board Approves Substantially Conditioned and Modified Transmission System Upgrade", press release, January 28, 2005.

45 State of Vermont Public Service Board, Order Re: Energy Efficiency Utility Budget for Calendar Years 2006, 2007 and 2008, 8/2/2006.

46 Efficiency Vermont Annual Plan, 2008-2009.

47 Efficiency Vermont Annual Plan, 2007-2008.

48 Massie, Jim, Nancy Wasserman, and Blair Hamilton, "Fast Capacity Reduction through Geographically Targeted, Aggressive Efficiency Investment: Early Results from a Vermont Experiment," in Proceedings of 2008 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 194-205.

*Table 1* [49]

**Characteristics of Vermont Geographically Targeted Areas (2007-2008)**

| | Urban vs. Rural | Size of Area | C&I Sales % | Large C&I Customers | Peak Period | 2007 Peak (MW) | Annual Load Growth w/o DSM | Projected Load Growth w/ Targeted DSM |
|---|---|---|---|---|---|---|---|---|
| **N. Chittenden** | Urban | Small | 65% | 72 | Summer | 64 | 4.3% | 1.2% |
| **Newport** | Urban | Small | 64% | 15 | Both | 18 | 1.7% | -0.5%[50] |
| **St. Albans** | Urban | Moderate | 64% | 42 | Summer | 29 | 3.4% | -3.3% |
| **Southern Loop** | Rural | Large | 48% | 38 | Winter | 70 | 3.4% | -3.4% |

MW of winter peak savings (across the two areas with winter peaks). These targets represented a 7- to 10-fold increase in the peak savings Efficiency Vermont had achieved in the same areas during the previous 18 months. It was estimated that peak demands would not only stop growing but would actually decline in three of the four areas. In the fourth area (Chittenden North), which had the fastest natural growth rate, load growth was projected to decline by about 75% (from 4.3% to 1.2% per year).

To meet these savings goals, Efficiency Vermont implemented a three-pronged strategy:

1. Intensive account management of large commercial and industrial customers (targeted to approximately 148 customers using more than 500 MWh/year) to identify opportunities for deep savings and to negotiate financial incentives (often greater than those offered in other parts of the state) designed to achieve those savings;
2. Launch of an aggressive small commercial/industrial program (targeting those using 40 to 500 MWh/year) in which high savings measures (primarily lighting measures, but also other cost-effective HVAC, refrigeration, and custom measures) designed to achieve an average of 15% savings per business are directly installed at no cost or very low cost to the customer; and
3. Aggressive local promotion of CFLs to residential and small business customers through both targeted marketing campaigns, community awareness campaigns, and the use of direct mail coupons.

All customers in the areas were also still eligible to participate in other statewide programs.

After the selection of the initial four targeted areas, a working group consisting of the state's largest utilities, Efficiency Vermont, and the Vermont Department of Public Service developed a set of criteria for future selections for geo-targeting:

- Areas experiencing high load growth;
- Areas with known concerns regarding the capacity of existing T&D infrastructure;
- Areas for which the minimum planning horizon for deferral was three years, with a preference for horizons of at least five years; and
- Areas for which there were "no other circumstances requiring immediate investment."[51]

Ultimately, decision-making on geo-targeting priorities was supposed to move to the Vermont System Planning Committee (VSPC), which VELCO was charged by the Board with initiating. Initially, "although the VSPC was formed and has been functioning, for all intents and purposes the selection process remained with the founding geotargeting utilities." This may have been because many parties still regarded geo-targeting as an experiment.[52] More recently, however, the VSPC has assumed the role it was intended to play and initiated a robust process to select targeted areas for future efforts.

Approximately one year into its delivery, one of the four initially targeted areas (Newport) was dropped from the geo-targeting program when the distribution utility determined

49 Massie et al and Navigant Consulting et al., "Process and Impact Evaluation of Efficiency Vermont's 2007-2009 Geotargeting Program," Final Report, Submitted to Vermont Department of Public Service, January 7, 2011, p. 103.

50 This is the forecasted growth in winter peak demand. The baseline peak demands for summer and winter were the same. Efficiency Vermont forecast that it could reduce summer peak by more than winter peak, however. That would make winter peak the more constraining variable.

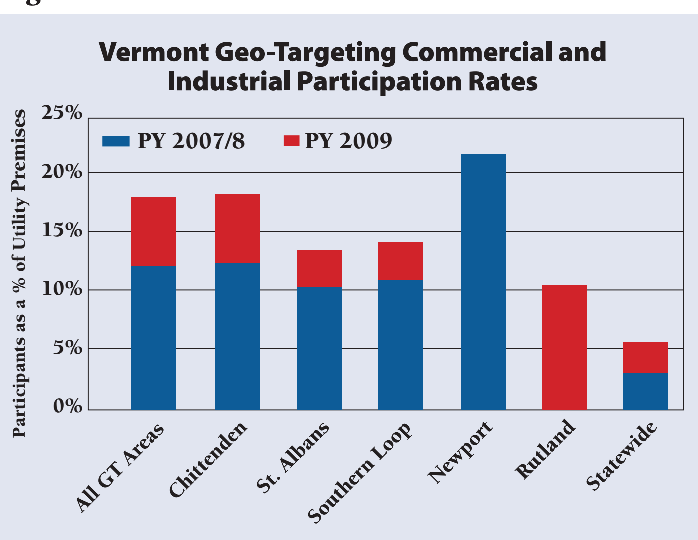
51 Navigant et al. (2011), p. 3.

52 Ibid.

that the substation whose rebuilding the program was intended to defer needed to be rebuilt for reasons other than load growth (i.e., "destabilization of the substation property due to river flooding").[53] Independent of that decision, a new target area – Rutland – was added to the program beginning in 2009.

A recent evaluation of the geo-targeting program suggests that it has had some success, although not all results were as good as hoped or projected. To begin with, efficiency program participation was considerably higher in geo-targeted areas than in the rest of the state. For example, as Figure 8 shows, commercial and industrial customers in geo-targeted areas participated at a rate nearly four times as great as their counterparts in the rest of the state. For those areas that were in their third year of geo-targeted DSM in 2009, the participation rate multiplier (compared to the rest of the state) declined to 2 to 1. The multiplier for the newly added geo-targeted region (Rutland), however, was roughly the same 4 to 1 ratio experienced by the other regions in their first two years.[54] Savings per participant were also higher than in the statewide programs – 20% to 25% higher for commercial and industrial customers and 30% higher for residential customers. That increase appears to reflect success in achieving greater depth of lighting savings per participant rather than increased penetration of non-lighting efficiency measures.[55] The net result of those two factors was summer peak demand savings that were three to five times greater (depending on the region) in the first couple of years of the program than would have been achieved under the statewide programs.[56]

*Figure 8* [57]




All told, over the 2007 to 2009 time period, the program achieved summer peak demand reductions in the targeted areas of 10 MW – about 70% of its goal. Winter peak demand savings were more problematic, with the program achieving only 4.1 MW of reductions, or only about 40% of its goal. Nevertheless, analysis of loads on individual feeders in geo-targeted areas suggests that geo-targeting program impacts "are detectable at the system level" and that the magnitude of savings observed at the utility system level was consistent with those estimated through evaluation of customer savings.[58]

Evaluation of the impacts of the observed peak demand reductions on the potential deferral of T&D investments has not yet been conducted. Central Vermont Public Service (the state's largest utility), however, has observed that it "has not been required to schedule the deployment of additional system upgrades in Rutland, St. Albans and Southern Loop areas." While it is difficult to know the extent to which that situation should be attributed to the geo-targeting of DSM, to changes in economic conditions (i.e., the recent economic recession), or to other factors, the Company has recommended to the Board that geo-targeting of DSM continue.[59]

## Central Maine Power

In June of 2010, the Maine Public Utilities Commission approved a settlement agreement reached by Central Maine Power (CMP) and a variety of other parties (including several public interest advocates) regarding a large transmission

53 Navigant et al. (2011), p. 26.

54 Navigant et al. (2011), pp. 85-87.

55 Navigant et al. (2011), pp. 89-91.

56 It is important to note that the statewide programs are already considered quite aggressive, achieving greater savings as a percent of sales than any state in the country in both 2007 (Eldridge, Maggie et al., *The 2009 State Energy Efficiency Scorecard*, ACEEE Report Number E097, October 2009) and 2008 (Molina, Maggie et al., *The 2010 State Energy Efficiency Scorecard*, ACEEE Report Number E107, October 2010).

57 Graphic courtesy of Navigant Consulting.

58 Navigant et al. (2011), p. 10.

59 Silver, Morris, Counsel for Central Vermont Public Service, letter to the Vermont Public Service Board regarding "EEU Demand Resources Plan – Track C, Geotargeting," January 18, 2011.

system upgrade project (the Maine Power Reliability Project) that the utility had proposed.[60] The settlement supported construction of most elements of the upgrade, but identified two areas – the Mid-Coast region and the city of Portland – where pilot projects to test the efficacy of non-transmission alternatives would be launched.

As part of the settlement, CMP was required to conduct a needs assessment for the two regions and develop a proposal for using non-transmission alternatives in conjunction with one of the intervening parties – Grid Solar. In March 2011, CMP and Grid Solar filed a proposed plan for the Mid-Coast region. The plan looked at a couple of different scenarios, ultimately recommending an approach that would require 25 to 29 MW of distributed resources in the Camden-Rockland area and another 10 MW of distributed resources in the Boothbay region to fully obviate the need for a transmission upgrade. It also proposed to use an RFP process to identify and acquire the least cost mix of resources to meet this need. It further suggested the resources be acquired in phases, with the first RFP covering needs from 2012 through 2015 (10 MW in Camden-Rockland and 6 MW in Boothbay). Subsequent RFPs would be developed and issued "based on load growth in the Mid-coast area, on the performance of distributed resources under contract pursuant to prior RFP(s), and on changes to the physical electric transmission and distribution system circuits in the Mid-Coast area." [61]

Under the proposal, any distributed resource would be eligible to respond to the RFP, including:

- Existing back-up generators (the plan identified 45 generators with a combined capacity of 25 MW in the region);
- New generators that could be acquired to provide both back-up capability to customers as well as distributed resources for the pilot;
- Demand response resources (as much as 15 MW were estimated to be in the region);
- Targeted energy efficiency (the plan estimating maximum achievable potential in the Mid-Coast region to be 15 MW, but suggested that 10 MW of that amount was already captured in CMP's load forecast, leaving only 5 MW to potentially be acquired);
- Solar PV (the plan suggested that solar PV would not likely be competitive with other resources, but that it may be appropriate to set aside a portion of the RFP as a "solar carve out" to test the applicability of PV as a transmission resource); and
- Storage (which was also estimated to be too expensive for initial rounds of procurement).

The plan noted that Vermont's experience with geographically targeted efficiency programs suggested that efficiency resources would likely be "highly competitive with other distributed resources." It also suggested that the Efficiency Maine Trust, which is responsible for and funded to implement statewide efficiency programs, could bid enhancements to its efficiency initiatives in the target region in response to the RFP. The plan left unaddressed, however, the question of how baseline levels of savings (from which additional savings from a more aggressive set of geographically targeted efforts would presumably be measured) would be established. It was also not clear whether the plan anticipated the possibility of other efficiency resource providers bidding in response to the RFP. [62]

These issues have not yet been fully explored. In the summer of 2011 the Maine PUC held a Technical Conference on the plan. Among the topics discussed were the impacts of both the economic recession and new (more stringent) reliability standards issued by the North American Electric Reliability Council (NERC) on the forecast resource needs. CMP and Grid Solar are expected to examine these issues and file a new needs analysis and plan in late November 2011. A second Technical Conference is expected to follow in December 2011.[63]

## NV Energy

In 2008 NV Energy faced a situation in a relatively rural portion of its service territory, east of Carson City, in which growth in demand was going to need to be met by either running the locally situated but relatively expensive Fort Churchill generating station more frequently or constructing a 30-mile, 345-kVA transmission line and new substation

60 Maine Public Utilities Commission, Order Approving Stipulation, Docket No. 2008-255, June 10, 2010.

61 Central Maine Power and Grid Solar, Non-Transmission Alternative Pilot Plan and Smart Grid Proposal including Attachments 1-7, filed under Docket No. 2008-255 (Phase II), March 25, 2011.

62 Ibid.

63 Personal communication with Beth Nagursky, Environment Northeast, 11/16/11.

to bring less expensive power from the more efficient Tracy generating facility (situated further north, about 20 miles east of Reno) to the region. When the local county commission began expressing concerns about permitting construction of the substation, regulators instructed the Company to increase the intensity of its DSM efforts in the targeted region as an alternative to meeting the area's needs economically:

> "…*the concentration of DSM energy efficiency measures in Carson City, Dayton, Carson Valley and South Tahoe has the potential to reduce the run time required for the Ft. Churchill generation units. The increased marketing costs and increased incentives and subsequent reduction in program energy savings required to attain an increased participation in the smaller market area are estimated to be more than offset by reduced fuel costs. Sierra Pacific, d.b.a. NV Energy, will make a reasonable effort within the approved DSM budget and programs to concentrate DSM activities in this area…*" [64]

NV Energy pursued a variety of efforts to either focus its existing DSM programs more intensely on the Fort Churchill area and/or launch new initiatives. This included:[65]

- **Non-Profit Agency Grants.** NV Energy gave priority to projects in the impacted area and marketed the program accordingly. In the end, 12 of the 35 applications it received were from the targeted area.
- **Energy Education.** NV Energy concentrated its education events in the region, ultimately holding 19 in 2009 – up from just two the previous year.
- **Low Income Weatherization.** NV Energy asked its implementation contractor to make a special effort to solicit program participation in the targeted area. Participation in the targeted area increased from just eight homes in 2008 to 57 in 2009.
- **ENERGY STAR Lighting and Appliances.** NV Energy concentrated marketing and outreach events in the Fort Churchill area, leading to an increase in participation of nearly 20% (although estimated savings did not increase due to changes in assumptions regarding average run times of CFLs).
- **Second Refrigerator Collection and Recycling.** NV Energy increased marketing efforts in the targeted region, in part through a targeted door-to-door campaign that also included distribution of nearly 100,000 CFLs to more than 16,000 homes. This resulted in increased participation in the refrigerator recycling program of nearly 15% in the targeted region, as well as substantial lighting savings.
- **Energy Smart Schools.** NV Energy offered an "Energy Master Planning Service" to the Carson City and Douglas County School Districts, but both declined the service. The utility also launched a new initiative to distribute CFLs to school district employees.
- **Commercial Retrofit Incentive.** NV Energy renegotiated its contract with its program vendor to support increased marketing in the targeted area, increase financial incentives by 25% in the targeted area, and concentrate all direct install efforts in the target area. The result was a more than 260% increase in savings in the area.
- **Sure Bet Hotel Motel.** NV Energy increased marketing support and financial incentives for this program as well, but no increase in participation was realized.

Of these efforts, the second refrigerator collection and recycling program (primarily the CFL distributions) and the commercial retrofit program were together responsible for the vast majority of the increased DSM savings in the region.[66]

At the same time as these efficiency efforts were launched, NV Energy's transmission staff began re-conductoring the existing 120-kVA line to the region to increase its carrying capacity. The economic recession also hit at the same time, dampening growth. As a result, the Company has not had to revisit the need for either the additional power line and substation or increasing the run time of the Fort Churchill generating station. The project has also facilitated the beginnings of "rich conversations" between demand resource planners and transmission planners within the Company.[67]

64 Jarvis, Daniel et al., *Targeting Constrained Regions: A Case Study of the Fort Churchill Generating Area,* 2010 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 178-189.

65 Sierra Pacific Power Company, 2010 Annual Demand Side Management Update Report, July 1, 2010, pp. 6-9.

66 Ibid, and Jarvis et al.

67 Personal communication with Larry Holmes, NV Energy, 11/9/11.

# 3. Lessons Learned

Although the actual implementation of efficiency as an alternative to T&D investments has not yet been what one might call "widespread," there are enough examples in sufficiently diverse circumstances to draw initial conclusions.

## Geographically Targeted Energy Efficiency Can Defer T&D Investments

A number of studies have suggested that aggressive, geographically targeted efficiency programs can meet T&D reliability objectives. More important, analyses of the actual deployment of efficiency as alternatives to T&D in several jurisdictions have concluded that supply-side investments were deferred for at least some period of time (e.g., Con Ed in New York City, Green Mountain Power's Mad River Valley Project in Vermont, PG&E's Delta Project in California, portions of PGE's project in downtown Portland, Oregon).

## Efficiency Can Be a Cost-Effective T&D Resource

There is less evidence regarding the cost-effectiveness of efficiency as an alternative to T&D upgrades. However, analysis of the most intensive and long-standing effort to defer T&D investments with efficiency programs – Con Ed's experience in New York City – clearly concluded that the geographically targeted programs were very cost-effective. Indeed, the T&D benefits alone were greater than the costs of the programs. When other benefits (e.g., energy savings and system peak demand savings) are included in the analysis, the geographically targeted efficiency programs had a benefit-to-cost ratio of about 3 to 1.

The realization that energy efficiency provides a variety of electric system benefits is critically important, as that broad range of benefits can often render the pursuit of more intensive efficiency programs in localized areas a "no regrets" strategy – at least from a purely economic perspective. Indeed, even though a determination of whether the recent Efficiency Vermont geo-targeting program has deferred T&D system upgrades has not yet been definitively made, evaluation of the program suggests it has been cost-effective – with a benefit cost-ratio of about 2 to 1 (under the Total Resource Cost Test) – even if no T&D investments are deferred.[68]

This suggests that, in most cases, the most important concerns regarding the deployment of efficiency as a T&D resource will likely be efficiency savings forecast issues (i.e., particularly uncertainty about whether enough customers will install enough efficiency measures to actually avoid a reliability-driven investment) and possibly equity issues (i.e., concerns about customers in targeted areas getting greater access to and/or greater financial incentives from efficiency programs than those in other areas).

## Stuff Happens! Unexpected Events Can Affect Benefits of Efficiency

It is worth noting that in several of the case studies examined for this report some or all of the T&D investment being considered for deferral ultimately ended up being constructed for reasons having nothing to do with the effectiveness of the deployment of efficiency resources. For example, part of PGE's project in Portland, Oregon (to defer a transformer upgrade for one commercial building) ended when the conversion from gas to electric cooling for the building added too much load to be offset by demand-side measures. More recently in Vermont, one of the original areas targeted for locally intensive DSM programs (Newport) was removed from the program when the existing substation became destabilized due to flooding, necessitating an immediate supply-side investment. In each of those cases, it could be concluded that the investments in efficiency programs ultimately provided either no T&D

68 Navigant et al. (2011), p. 100. Similar analyses for other case studies examined are not available.

benefit or very little benefit.

It is important to recognize that forecasting uncertainty works in both directions, however. In several of the examples discussed in this paper it appears as if efficiency investments not only permitted deferral of a T&D investment, but permanently eliminated the need for the investment. This happened either because the efficiency savings realized were greater than forecast (e.g., in one of the commercial buildings treated by PGE's program in Portland, Oregon) or because the efficiency investments bought enough time for more fundamental changes in demand to take hold (e.g., Con Ed's conclusion that $85 million in T&D investments that it otherwise would have made may now never be needed).

The bottom line is that there are a variety of risks associated with forecasting of T&D system needs that can affect the potential benefits of using efficiency to defer T&D system investments. These include:

- The reliability risk of under-forecasting demand growth;
- The economic risk of over-building the T&D system due to over-forecasting of demand growth; and
- Both the reliability risk (if it takes longer than expected) and the economic risk (if it ends up costing more)[69] of siting new poles and wires.

It could be argued that efficiency programs are more likely to mitigate than to exacerbate these risks. To begin with, many efficiency programs are "load-following." For example, efficiency programs designed to promote efficiency in the construction of new buildings will generally have lower participation and savings when construction slows (i.e., when savings are least needed) and higher participation and savings when construction accelerates (i.e., when savings are most needed). Similarly, efficiency programs often have a harder time convincing home-owners and businesses to participate – and therefore have a harder time meeting savings goals – during difficult economic times (i.e., when loads are not growing fast and therefore concerns about exceeding T&D system capacity are lower); they often have an easier time recruiting participants and exceeding savings goals during good economic times (i.e., when loads are naturally growing faster, imposing greater strains on T&D systems). Indeed, the reality that Efficiency Vermont launched its geo-targeting program just before the recent deep economic recession was probably a contributing factor to their failure to meet initial savings goals. On the other hand, as Central Vermont Public Service has implied, the recession is likely part of the reason the Company has not had to deploy additional system upgrades in its portion of the targeted areas.

## Sufficient Lead Time is Critical

It usually takes time to generate enough savings from energy efficiency programs to defer T&D system upgrades. The programs must be planned, developed, and then marketed to consumers before any savings are realized. Reaching a large segment of the eligible market requires on-going marketing and business development efforts. Initial strategies may not be as successful as anticipated, so programs are more likely to be successful if there is time to refine them in response to market feedback. As discussed above, PG&E's Delta Project did not have that luxury and, as a result, ended up falling short of overall savings goals and spending more per unit of savings than originally planned. Even though a very cost-effective strategy was identified part of the way through the project, there was not enough time for it to gain enough traction to offset the less effective results of some of the initially pursued elements. Sufficient lead time may also better enable efficiency program managers to demonstrate to T&D system planners and engineers that efficiency strategies are affecting localized peak loads. Parts of PGE's downtown Portland project ultimately failed to defer T&D upgrades not because the efficiency savings were inadequate, but rather because T&D planners and engineers did not have sufficient confidence that the savings would be achieved and be reliable and persistent.

To be sure, the amount of lead time necessary to enable efficiency programs to defer T&D investments will vary

69 For example, in July 2005, about six months after its proposal to construct a major new transmission line and make other related improvements was approved by the Vermont Board of Public Utilities, VELCO filed with the Board a revised cost estimate that was nearly double the estimate it had made two to three years earlier and presented during the course of the hearing on the project. In order of importance, the increase was attributed to a high rate of inflation for the materials and services needed, regulatory conditions of the approval, and better (higher) estimates of the materials it would need (State of Vermont Public Service Board, Order on Remand RE: Reopening Proceedings, Docket 6860, 9/23/2005).

from project to project. In general, shorter lead times will be needed when the number of customers that must be served by efficiency programs in order to generate sufficient savings is small. One key to ensuring there is sufficient lead time is to conduct more systematic planning for meeting T&D needs, including long-term forecasting of potential needs, integrating the forecasting of such needs with forecasting of savings from system-wide efficiency initiatives, and including analysis of potential additional, localized efficiency programs in early stages of assessment of options for meeting T&D needs.

## Smaller is Easier

In general, the smaller the area being addressed, the easier it is to consider efficiency and other non-wires alternatives to T&D investments. Smaller areas mean that efficiency savings need to be acquired from fewer customers. That in turn means that it is often easier to characterize the opportunity for efficiency investments accurately. It also means that shorter lead times will be needed. For example, deferring a transformer upgrade on a single large commercial building may not require much time if one need just convince a single owner of the building to make an efficiency investment. Alternatively, deferring distribution substations or transmission lines serving many thousands of customers will usually take longer unless there are just a few large customers who, if served by an efficiency program, could impact localized peak demands significantly.

## Distribution is Easier than Transmission

Deferring distribution system investments is generally easier than deferring transmission investments because the non-wires solutions will generally be smaller in scope (see discussion above). In addition, distribution system planning is generally less technically complex, involves fewer parties, does not involve regional ISOs/RTOs, and does not involve regional cost-allocation frameworks that often bias investments in favor of "poles and wires" solutions.

## Cross-Discipline Communication is Critical

This may seem self-evident, but it is critical nonetheless. T&D planners and engineers are often skeptical of the potential for end-use efficiency to reliably substitute for poles, wires, and other T&D "hardware." They worry that customers themselves are unreliable. Similarly, staff responsible for administration of programs that promote efficiency, load control, distributed generation, or other demand resources typically do not fully understand the complexities of the reliability issues faced by T&D system planners. Both need to better understand the needs and capabilities of the other.

It can take time to develop the relationships and confidence necessary for efficiency program implementers and their evaluated results and T&D system engineers to work together effectively. Those relationships and that trust must be developed, however, if efficiency programs are to be as successful as possible in deferring T&D investments.

Upper management can be very important in setting expectations that such communication and cross-discipline learning take place within a utility. It is much more difficult to institutionalize such communication when transmission planning has regional elements and implications that necessarily involve the ISO/RTO.

## Integrate Efficiency with Other Distributed Resources

Although efficiency programs can sometimes be sufficient to defer T&D investments, other times they will not be. They can, however, be married with promotion of demand-response and distributed generation initiatives to meet the same objective.

# 4. Recommendations

Though several pilot projects in the past and some more substantial projects today appear to have demonstrated that efficiency programs can be a cost-effective T&D resource, such efforts remain uncommon. Put another way, the potential economic and other benefits of using geographically targeted efficiency programs as a T&D resource are largely being ignored today. Some fundamental policy changes are required if that is to change. In this concluding section of the paper we discuss the policies that should be explored if efficiency's potential is to be realized.

## Require Least-Cost T&D Planning

As noted above, both economic incentives in many states and system planning culture have made "poles and wires" (or T&D hardware) the default solution to T&D-related reliability issues almost everywhere. Experience to date suggests that the only way that will change is if T&D planners are required by legislators or regulators to analyze alternatives and choose the least-cost option.[70]

Over the past decade, several jurisdictions have institutionalized such processes. Several notable examples are summarized below. There are certainly costs to such processes – both for the utilities doing the planning and for regulatory oversight. Feedback from several jurisdictions, however, suggests that the process evolves – as it is tested and refined – to one in which the burden on the utility is not only manageable but also much more than offset by cost savings. Once that point is reached and utilities are meeting a high standard in their work, the burden on regulators should be quite modest.

### Rhode Island

In 2006, Rhode Island adopted a "System Reliability Procurement" policy that requires utilities to submit system reliability procurement plans every three years. Guidelines detailing what to include in those plans were adopted more recently (see Appendix A). Those guidelines make clear that plans must consider non-wires alternatives – including energy efficiency, distributed generation, and demand response – whenever the T&D need:

- Is not based on an asset condition;
- Will likely cost more than $1 million to address;
- Would require no more than a 20% reduction in peak load to defer; and
- Would not require investment in a "wires solution" to begin for at least 36 months.

For such cases, the plans must include analysis of financial impacts, risks, the potential for synergistic benefits, and other aspects of both wires and non-wires alternatives.[71]

### Vermont

Vermont has long imposed an integrated resource planning requirement on its utilities. However, the passage of Act 61 in 2005 – which reinforced those requirements by specifying minimum 10-year planning horizons, required the plans to be filed at least every three years, and required public meetings (in areas close to potential T&D upgrades) at which plans are presented (see Appendix B for legislative language) – has begun to make the process more rigorous. Indeed, VELCO and Efficiency Vermont are now working together to regularly reconcile and integrate

70 Note that this works only to the extent that states actually control the planning process. Although they do for distribution system investments, responsibility for transmission planning decisions is shared with regional ISOs/RTOs. That has lessened states ability to effectively impose least-cost planning requirements. Recent FERC Order 1000, which requires ISOs/RTOs to consider state policies in planning decisions, may give states more influence in the future.

71 Rhode Island Standards for Least Cost Procurement and System Reliability Planning.

their respective forecasts of baseline demand and efficiency program savings.[72]

## Bonneville Power Administration

Although not required by legislation or regulation, in 2002 BPA launched a Non-Wires Solutions (NWS) initiative in which it committed to investigating "least-cost solutions that may result in deferring potential transmission reinforcement projects."[73] A year later, BPA formed a Non-Wires Solutions Round Table composed of key stakeholder groups in the region to assist it in these endeavors.[74] It then developed a formal process by which non-wires solutions – including energy efficiency, demand response, load control, and distributed generation – would be routinely assessed. To begin with, transmission planners annually assess potential transmission needs over the next 10 to 15 years. That assessment is tied to the Western Electricity Coordinating Council's power flow and planning framework.[75] Once a transmission need is identified by BPA's Transmission Business Line, an initial "screening" is conducted to determine whether the project is a candidate for possible non-wires solutions. A project qualifies for an analysis of non-wires solutions if it meets three criteria:

1. The transmission project cost is estimated to be at least $5 million;
2. The project need is driven by load growth; and
3. The project need is at least eight years out.[76]

If these criteria are met, a high level economic assessment is conducted using a simplified spreadsheet template that has been developed specifically for this purpose. The analysis includes all of the potential benefits of non-wires solutions. Estimates of energy savings and capacity savings benefits are based on results of the Northwest Power Planning Council's integrated resource plans (conducted every five years). Avoided transmission costs are estimated for the specific project under consideration. If the analysis suggests both that there are sufficient non-wires resources to defer a project and that the deferral could be cost-effective, a detailed feasibility study is conducted. If that study confirms that the non-wires solution is indeed feasible, then the benefits, costs, and risks of both traditional transmission and non-wires solutions are compared to decide which strategies to pursue. This process is summarized in Figure 9. BPA went through this process on four different occasions between 2002 and 2006. In all of those cases a determination was made that the traditional transmission strategy was needed.

BPA recently reconvened its Non-Wires Round Table to consider new regional transmission needs in this same framework. Three potential non-wires projects are currently undergoing intensive analysis and discussion. Energy efficiency is an element of the non-wires solution being considered for both the I-5 corridor in Oregon and the Hooper Springs area in Idaho. Efficiency plays a more central role in a third potential project that has not yet been made public.[77]

72 This has not been without its challenges, because assumptions about such things as treatment of baseline efficiency conditions, the level of "naturally occurring" efficiency (related to free rider assumptions in efficiency savings forecasts), and other key issues are sometimes different or inconsistent (see Enterline, Shawn and Eric Fox, *Integrating Energy Efficiency into Utility Load Forecasts*, in Proceedings of the 2010 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 86-96).

73 GDS Associates, "Process Evaluation of the Non-Wires Solution Initiative," prepared for BPA, June 8, 2007.

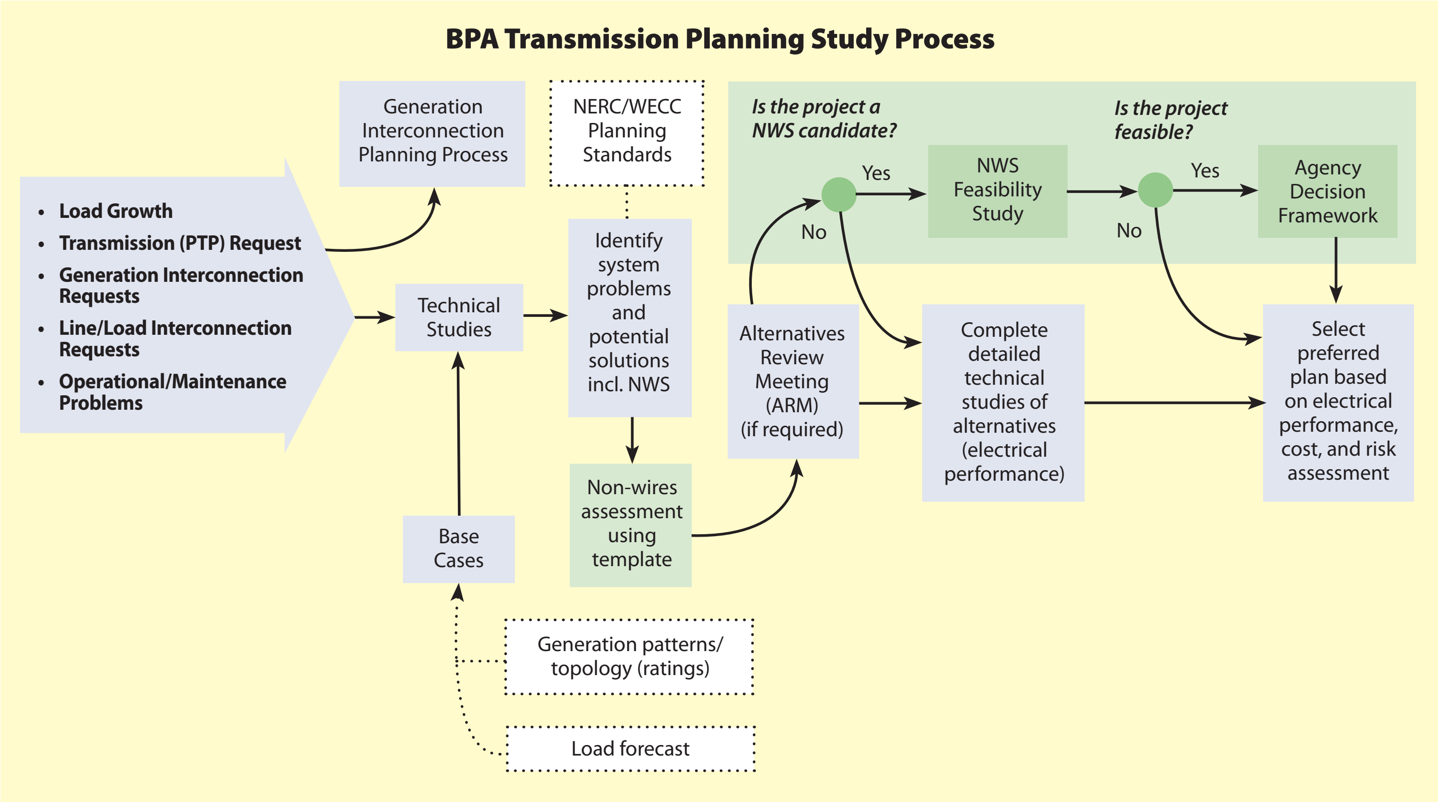
74 Although the Round Table has been organized to function collaboratively, its input is purely advisory. BPA makes all final decisions on how to address transmission needs.

75 Personal communication with Mike Weedall, Ottie Nabors, and Josh Binus, Bonneville Power Administration, 4/27/11.

76 Nabors, Ottie, "Non-Wires Alternatives Screening Process & Evaluation," presentation at the Non-Wires Round Table, April 15, 2011.

77 Personal communication with Mike Weedall, BPA, 12/23/11.

*Figure 9* [78]




## Require Consideration of Integrated Solutions

Efficiency is one of several types of distributed resources – demand response, load control, and distributed generation are other notable examples – that can help to cost-effectively defer T&D investments. Indeed, there may be important synergies in combining deployment of efficiency and other distributed resources (e.g., efficiency and demand response and potentially even distributed generation can often be "sold" to customers more effectively if sold together). Any requirement for least-cost planning thus should make clear that all options, including different combinations of distributed resources, should be considered.

The ability for states to require either least-cost planning or consideration of integrated solutions is clear with respect to distribution system planning, but more complicated for transmission planning because of transmission's regional implications and the involvement of regional ISOs/RTOs. Nevertheless, states have influenced transmission planning, and the recent FERC Order 1000, which requires ISOs/RTOs to consider state policies in their planning decisions, may give them more clout in the future.

## Institutionalize a Long-Term Planning Horizon

The longer the lead time, the more likely it will be that efficiency (or other distributed resources) could cost-effectively defer traditional T&D investments. This suggests it is critical that assessments of T&D needs are both long-term and conducted on a regular basis. As noted above, although they are all still refining their processes, all of the jurisdictions that are currently seriously considering non-wires alternatives to T&D investments are routinely forecasting T&D needs at least 10 years into the future. Con Ed develops a 10-year plan for T&D needs. Vermont requires an annual plan that looks out a minimum of 10 years. VELCO, Vermont's transmission utility, has chosen to forecast 20 years out. Similarly BPA looks at transmission needs 10 to 15 years into the future.

78 Graphic from Nabors, Ottie, "Non-Wires Alternatives Screening Process & Evaluation," presentation at the Non-Wires Round Table, April 15, 2011.

## "Level the Playing Field" in Payment for Wires and Non-Wires Alternatives

One of the biggest barriers to serious consideration of efficiency (and other demand resources) as alternatives to T&D investments is the unequal treatment of the costs of wires and non-wires solutions. For example, nearly 90% of the nearly $290 million cost of VELCO's Northwest Reliability Project in Vermont has been deemed by the New England ISO to be eligible for Pooled Transmission Facility (PTF) treatment – or spread across the New England region.[79] Because Vermont represents a relatively small portion of the total regional power pool load, its ratepayers pay only about 5% of PTF costs. Its rate-payers thus will ultimately bear less than 20% of total project costs. The ISO does not give PTF treatment to non-wires solutions. As a result, if the state had pursued a non-wires solution to its transmission reliability needs, it would have borne 100% of the costs of the project.

Such policies represent enormous disincentives to pursue non-wires solutions – even if they are less expensive than traditional transmission investments. Unbalanced treatment of wires and non-wires solutions needs to be addressed if least-cost solutions are to be routinely and seriously considered.

## Collect More Data on Efficiency's Impacts

In much of the country, relatively little end-use metered data on the hourly and seasonal impacts of efficiency resources has been collected and made public over the past two decades. As a result, many jurisdictions now rely on very old end-use metering studies when developing hourly load shapes for efficiency measures. Such load shapes are essential to estimating the impacts of efficiency resources on localized transmission or distribution system peaks (peak hours can vary considerably from one distribution element to another, even within the same utility service territory). Having more data of this kind should make it easier to address concerns of T&D system planners.

It is worth noting that the New England region may be ahead of much of the rest of the country in this regard, in part because the region's forward capacity market requires efficiency resource providers to use studies that are less than five years old to document achievement of the system peak demand savings that are bidding into the market. That requirement has resulted in a number of different end-use metering studies that have not only documented savings at the time of the regional system peak, but also at all other hours of the day. In many cases, the studies have been undertaken at the regional level – with all states sharing the cost – as a way to make them affordable.

## Start with Pilot Projects

Virtually every jurisdiction that genuinely considered efficiency as a potential cost-effective alternative to T&D investments started with pilot projects. Much has been learned from those pilots. The pilots also offered important venues for facilitating the mutual education of system engineers and efficiency program managers. Experience to date suggests that a pilot project or two will not bridge the cultural chasms between these two groups. They can be important steps in that process, however.

## Leverage "Smart Grid" Investments

A number of utilities have recently made or are about to make significant investments in advanced metering, customer feedback mechanisms, and other "smart grid" features. Customer and end-use data collected through such systems may enable better assessments of the potential for efficiency to serve as a T&D resource in general, and perhaps more important, in specific geographic areas.

79 ISO New England, "Summary of ISO-NE Reviewed TCA Applications under Schedule 12C of the Tariff" – Status as of 2/18/2011 (http://www.iso-ne.com/trans/pp_tca/status/tca_application_status.pdf )

**Appendix A**

# Rhode Island Standards for Least Cost Procurement and System Reliability Planning – Excerpt on Distributed Resources in Relation to T&D Investment

## Chapter 2 - System Reliability Procurement

### Section 2.1 Distributed/Targeted Resources in Relation to T&D Investment

A. The Utility System Reliability Procurement Plan ("The SRP Plan") to be submitted for the Commission's review and approval on September 1, 2011 and triennially thereafter on September 1, shall propose general planning principles and potential areas of focus that incorporate non-wires alternatives (NWA) into the Company's distribution planning process for the three years of implementation beginning January 1 of the following year.

B. Non-Wires Alternatives (NWA) may include but are not limited to:
   a. Least Cost Procurement energy efficiency baseline services
   b. Peak demand and geographically-focused supplemental energy efficiency strategies
   c. Distributed generation generally, including combined heat and power and renewable energy resources (predominately wind and solar, but not constrained)[80]
   d. Demand response
   e. Direct load control
   f. Energy storage
   g. Alternative tariff options

C. Identified transmission or distribution (T&D) projects with a proposed solution that meet the following criteria will be evaluated for potential NWA that could reduce, avoid or defer the T&D wires solution over an identified time period.
   a. The need is not based on asset condition;
   b. The wires solution, based on engineering judgment, will likely cost more than $1 million;
   c. If load reductions are necessary, then they are expected to be less than 20 percent of the relevant peak load in the area of the defined need;
   d. Start of wires alternative is at least 36 months in the future; and
   A more detailed version of these criteria may be developed by the distribution utility with input from the Council and other stakeholders.

D. Feasible NWAs will be compared to traditional solutions based on the following:
   a. Ability to meet the identified system needs
   b. Anticipated reliability of the alternatives
   c. Risks associated with each alternative (licensing and permitting, significant risks of stranded investment, sensitivity of alternatives to differences in load forecasts, emergence of new technologies)
   d. Potential for synergy savings based on alternatives that address multiple needs
   e. Operational complexity and flexibility
   f. Implementation issues
   g. Customer impacts
   h. Other relevant factors

E. Financial analyses of the preferred solution(s) and alternatives will be conducted to the extent feasible. The selection of analytical model(s) will be subject to Public Utilities Commission review and approval. Alternatives may include the determination of deferred investment savings from NWA through use of net present value of the deferred revenue requirement analysis or the net present value of the alternatives according to the Total Resource Cost Test (TRC). The selection of an NWA shall be informed by the considerations approved by the Public Utilities Commission which may include, but not be limited to, those issues enumerated in (D), the deferred revenue requirement savings and an evaluation of costs and benefits according to the TRC. Consideration of the net present value of resulting revenue

80 In order to meet the statute's environmental goals, generation technologies must comply with all applicable general permitting regulations for smaller-scale electric generation facilities.

requirements may be used to inform the structure of utility cost recovery of NWA investments and to assess anticipated ratepayer rate and bill impacts.

F. For each need where an NWA is the preferred solution, the distribution utility will develop an implementation plan that includes the following:
   a. Characterization of the need
      i. Identification of the load-based need, including the magnitude of the need, the shape of the load curve, the projected year and season by which a solution is needed, and other relevant timing issues
      ii. Identification and description of the T&D investment and how it would change as a result of the NWA
      iii. Identification of the level and duration of peak demand savings and/or other operational functionality required to avoid the need for the upgrade
      iv. Description of the sensitivity of the need and T&D investment to load forecast assumptions
   b. Description of the business as usual upgrade in terms of technology, net present value, costs (capital and O&M), revenue requirements, and schedule for the upgrade
   c. Description of the NWA solution, including description of the NWA solution(s) in terms of technology, reliability, cost (capital and O&M), net present value, and timing
   d. Development of NWA investment scenario(s)
      i. Specific NWA characteristics
      ii. Development of an implementation plan, including ownership and contracting considerations or options
      iii. Development of a detailed cost estimate (capital and O&M) and implementation schedule

G. Funding Plan
   The Utility shall develop a funding plan based on the following sources to meet the budget requirement of the system reliability procurement plan. The Utility may propose to utilize funding from the following sources for system reliability investments:
      i. Capital funds that would otherwise be applied towards traditional wires based alternatives
      ii. Existing Utility EE investments as required in Section I of these Standards and the resulting Annual Plans
      iii. Additional energy efficiency funds to the extent that the NWA can be shown to pass the TRC test with a benefit to cost ratio of greater than 1.0 and such additional funding is approved
      iv. Utility operating expenses to the extent that recovery of such funding is explicitly allowed
      v. Identification of significant customer contribution or third party investment that may be part of an NWA based on benefits that are expected to accrue to the specific customers or third parties
      vi. Any other funding that might be required and available to complete the NWA

H. Annual SRP Plan reports should be submitted on November 1. Such reports will include but are not limited to:
   a. A summary of projects where NWA were considered;
   b. Identification of projects where NWA were selected as a preferred solution; and a summary of the comparative analysis following the criteria outlined in sections (D) and (E) above;
   c. Implementation plan for the selected NWA projects;
   d. Funding plan for the selected NWA projects;
   e. Recommendations on pilot distribution and transmission project alternatives for which it will utilize selected NWA reliability and capacity strategies. These proposed pilot projects will be used to inform or revise the system reliability procurement process in subsequent plans;
   f. Status of any previously selected and approved projects and pilots;
   g. Identification of any methodological or analytical tools to be developed in the year;
   h. Total SRP Plan budget, including administrative and evaluation costs.

I. The Annual SRP Plan will be reviewed and funding approved by the Commission prior to implementation.

### Appendix B

# Excerpts from Vermont's Act 61

## Sec. 8. Advocacy For Regional Electricity Reliability Policy

It shall be the policy of the state of Vermont, in negotiations and policy-making at the New England Independent System Operator, in proceedings before the Federal Energy Regulatory Commission, and in all other relevant venues, to support an efficient reliability policy, as follows:

(1) When cost recovery is sought through region-wide regulated rates or uplift tariffs for power system reliability improvements, all available resources – transmission, strategic generation, targeted energy efficiency, and demand response resources – should be treated comparably in analysis, planning, and access to funding.

(2) A principal criterion for approving and selecting a solution should be whether it is the least-cost solution to a system need on a total cost basis.

(3) Ratepayers should not be required to pay for system upgrades in other states that do not meet these least-cost and resource-neutral standards.

(4) For reliability-related projects in Vermont, subject to the review of the public service board, regional financial support should be sought and made available for transmission and for distributed resource alternatives to transmission on a resource-neutral basis.

(5) The public service department, public service board, and attorney general shall advocate for these policies in negotiations and appropriate proceedings before the New England Independent System Operator, the New England Regional Transmission Operator, the Federal Energy Regulatory Commission, and all other appropriate regional and national forums. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.

(6) In addressing reliability problems for the state's electric system, Vermont retail electricity providers and transmission companies shall advocate for regional cost support for the least cost solution with equal consideration and treatment of all available resources, including transmission, strategic distributed generation, targeted energy efficiency, and demand response resources on a total cost basis. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.

### Transmission and Distribution Planning

### *Sec. 9. 30 V.S.A. § 218c is amended to read:*
### § 218C. Least Cost Integrated Planning

(d)(1) Least cost transmission services shall be provided in accordance with this subsection. Not later than July 1, 2006, any electric company that does not have a designated retail service territory and that owns or operates electric transmission facilities within the state of Vermont, in conjunction with any other electric companies that own or operate these facilities, jointly shall prepare and file with the department of public service and the public service board a transmission system plan that looks forward for a period of at least ten years. A copy of the plan shall be filed with each of the following: the house committees on commerce and on natural resources and energy and the senate committees on finance and on natural resources and energy. The objective of the plan shall be to identify the potential need for transmission system improvements as early as possible, in order to allow sufficient time to plan and implement more cost-effective non-transmission alternatives to meet reliability needs, wherever feasible. The plan shall:

(A) identify existing and potential transmission system reliability deficiencies by location within Vermont;

(B) estimate the date, and identify the local or regional load levels and other likely system conditions at which these reliability deficiencies, in the absence of further action, would likely occur;

(C) describe the likely manner of resolving the identified deficiencies through transmission system improvements;

(D) estimate the likely costs of these improvements;

(E) identify potential obstacles to the realization of these improvements; and

(F) identify the demand or supply parameters that generation, demand response, energy efficiency or other non-transmission strategies would need to address to resolve the reliability deficiencies identified.

(2) Prior to the adoption of any transmission system plan, a utility preparing a plan shall host at least two public meetings at which it shall present a draft of the plan and facilitate a public discussion to identify and evaluate non-transmission alternatives. The meetings shall be at separate locations within

the state, in proximity to the transmission facilities involved or as otherwise required by the board, and each shall be noticed by at least two advertisements, each occurring between one and three weeks prior to the meetings, in newspapers having general circulation within the state and within the municipalities in which the meetings are to be held. Copies of the notices shall be provided to the public service board, the department of public service, any entity appointed by the public service board pursuant to subdivision 209(d)(2) of this title, the agency of natural resources, the division for historic preservation, the department of health, the scenery preservation council, the agency of transportation, the attorney general, the chair of each regional planning commission, each retail electricity provider within the state, and any public interest group that requests, or has made a standing request for, a copy of the notice. A verbatim transcript of the meetings shall be prepared by the utility preparing the plan, shall be filed with the public service board and the department of public service, and shall be provided at cost to any person requesting it. The plan shall contain a discussion of the principal contentions made at the meetings by members of the public, by any state agency, and by any utility.

(3) Prior to the issuance of the transmission plan or any revision of the plan, the utility preparing the plan shall offer to meet with each retail electricity provider within the state, with any entity appointed by the public service board pursuant to subdivision 209(d)(2) of this title, and with the department of public service, for the purpose of exchanging information that may be relevant to the development of the plan.

(4)(A) A transmission system plan shall be revised:
- (i) within nine months of a request to do so made by either the public service board or the department of public service; and
- (ii) in any case, at intervals of not more than three years.

(B) If more than 18 months shall have elapsed between the adoption of any version of the plan and the next revision of the plan, or since the last public hearing to address a proposed revision of the plan and facilitate a public discussion that identifies and evaluates nontransmission alternatives, the utility preparing the plan, prior to issuing the next revision, shall host public meetings as provided in subdivision (2) of this subsection, and the revision shall contain a discussion of the principal contentions made at the meetings by members of the public, by any state agency, and by any retail electricity provider.

(5) On the basis of information contained in a transmission system plan, obtained through meetings held pursuant to subdivision (2) of this subsection, or obtained otherwise, the public service board and the department of public service shall use their powers under this title to encourage and facilitate the resolution of reliability deficiencies through nontransmission alternatives, where those alternatives would better serve the public good. The public service board, upon such notice and hearings as are otherwise required under this title, may enter such orders as it deems necessary to encourage, facilitate or require the resolution of reliability deficiencies in a manner that it determines will best promote the public good.

(6) The retail electricity providers in affected areas shall incorporate the most recently filed transmission plan in their individual least cost integrated planning processes, and shall cooperate as necessary to develop and implement joint least cost solutions to address the reliability deficiencies identified in the transmission plan.

(7) Before the department of public service takes a position before the board concerning the construction of new transmission or a transmission upgrade with significant land use ramifications, the department shall hold one or more public meetings with the legislative bodies or their designees of each town, village, or city that the transmission lines cross, and shall engage in a discussion with the members of those bodies or their designees and the interested public as to the department's role as public advocate.

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# Other recent RAP publications on energy efficiency include the following:

## Residential Efficiency Retrofits: A Roadmap for the Future

Roughly half of all efficiency and/or carbon emission reduction in North American and European buildings can be achieved through retrofit improvements to existing homes. In this publication, RAP offers a roadmap to help policymakers and practitioners design and implement a comprehensive residential retrofit strategy. We present eight principles for success based on two decades of international experience, designed to achieve the level of energy savings that will be needed to address the challenge of climate change.

The Executive Summary of this report is available separately in English and German at: http://raponline.org/document/download/id/4424.

The full report is available at: http://www.raponline.org/document/download/id/918

## Prices and Policies: Carbon Caps and Efficiency Programmes for Europe's Low-Carbon Future

This paper was presented at the 2011 ECEEE Summer Study.

With the adoption of the Climate and Energy Package in 2008, European decision-makers created an integrated suite of policies to reduce carbon emissions, increase renewable energy production, and advance energy savings. As the EU ETS moves to carbon auctioning, decision-makers must continue to link carbon prices with other policy tools to meet Europe's adopted carbon and sustainable development goals. This paper demonstrates how energy efficiency (EE) policies can help meet ETS goals at lower cost, creating space to tighten carbon caps, and/or reduce the cost of protecting high-emitting industries and new Member States. Smart "complementary policies" can directly link ETS and EE strategies, especially by using auction revenue for EE programmes. Complementary policies are also needed to support low-carbon power markets, grid expansion, and renewable power investment across Europe.

The full paper is available at: http://www.raponline.org/document/download/id/931

## Who Should Deliver Ratepayer Funded Energy Efficiency? A 2011 Update

This report describes policy options and approaches for administering ratepayer-funded electric energy efficiency programs in US states. It reviews how states have administered energy efficiency programs to learn what lessons their experience offers, and describes the most important factors states should consider with different administrative models. State legislators and utility regulators will find this report useful as they consider ways for energy efficiency administration to be more effective, both in states that are considering the question for the first time, and in more experienced states that are implementing significant increases in their savings goals. RAP's first version of this report was written in 2003.

The full report is available at: http://www.raponline.org/document/download/id/4707

## Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements

While utilities and their regulators are familiar with the energy savings that energy efficiency measures can provide, they may not be aware of how these same measures also provide very valuable peak capacity benefits in the form of marginal reductions to line losses that are often overlooked in the program design and measure screening. This paper is the first of two that the Regulatory Assistance Project is publishing on the relationship between energy efficiency and avoiding line losses.

The full report is available at: http://www.raponline.org/document/download/id/4537

## Achieving Energy Efficiency: A Global Best Practices Guide on Government Policies

This best practices guide provides a summary overview of the most effective policy mechanisms that regional, national, state or local governments at the executive, legislative or regulatory level can adopt to achieve significant energy efficiency in buildings, processes and equipment used in the residential, commercial, industrial, public and institutional sectors. By policy mechanism, we mean specific laws, regulations, processes and implementation strategies that foster the development and use of products and services which require less energy input to deliver the same or more productivity and output. Our focus is on how government policies can accelerate and increase efficiency investments to achieve additional savings. We do not address best practices in the design or delivery of efficiency programs that would flow from these policies. Nor do we address tariff structures or energy pricing and financing tools that can be employed to help end users invest in efficiency.

The full report is available at: http://www.raponline.org/document/download/id/4781

## Regulatory Mechanisms to Enable Energy Provider Delivered Energy Efficiency

The Regulatory Mechanisms to Enable Energy Provider Delivered Energy Efficiency paper identifies varied, but complementary, government regulatory mechanisms utilized worldwide to mobilize the resources of energy providers to implement investments in energy. The paper identifies and describes twelve types of regulatory mechanisms that governments use effectively to: mobilize energy provider investments directly; facilitate investments in demand-side resources; or implement policies and programs that underpin important elements of successful investment programs. The paper also explains how each regulatory mechanism functions in different market settings to mobilize resources or enable effective programs, identifies key issues that ensure successful implementation, and then outlines an example of how at least one jurisdiction has achieved successful implementation of the mechanism.

The full report is available at: http://www.raponline.org/document/download/id/4872

*Other documents on energy efficiency and other topics are available on The Regulatory Assistance Project website at:*

**www.raponline.org**

# Acronym Glossary

| | |
|---|---|
| **ACEEE** | American Council for an Energy Efficient Economy |
| **AMI** | Advanced Metering Infrastructure |
| **BPA** | Bonneville Power Administration |
| **C & I** | Commercial and Industrial |
| **CFLs** | Compact Fluorescent Light Bulbs |
| **CMP** | Central Maine Power |
| **Con Ed** | Consolidated Edison |
| **DR** | Demand Response |
| **DSM** | Demand-Side Management |
| **EEI** | Edison Electric Institute |
| **EPRI** | Electric Power Research Institute |
| **ESCO** | Energy Service Company |
| **FCM** | Forward Capacity Market |
| **FERC** | Federal Energy Regulatory Commission |
| **GMP** | Green Mountain Power |
| **ISO** | Independent System Operator |
| **NERC** | North American Electric Reliability Council |
| **NWS** | Non-Wires Solutions |
| **PGE** | Portland General Electric |
| **PG&E** | Pacific Gas and Electric |
| **PTF** | Pooled Transmission Facility |
| **PTP** | Point-to-point |
| **RTO** | Regional Transmission Organization |
| **SPWG** | State Program Working Group |
| **SRP** | System Reliability Procurement |
| **T&D** | Transmission and Distribution |
| **TRC** | Total Resource Cost |
| **VELCO** | Vermont Electric Power Company |
| **VSPC** | Vermont System Planning Committee |
| **WECC** | Western Electricity Coordinating Council |

**The Regulatory Assistance Project (RAP)** is a global, non-profit team of experts focused on the long-term economic and environmental sustainability of the power and natural gas sectors. We provide technical and policy assistance on regulatory and market policies that promote economic efficiency, environmental protection, system reliability and the fair allocation of system benefits among consumers. We have worked extensively in the US since 1992 and in China since 1999. We added programs and offices in the European Union in 2009 and plan to offer similar services in India in the near future.
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| DOC | Code | # | Description | Criteria/Category | Benefit/Comment | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | UES Total Budget | | 23,110,646 | 21,850,000 | 22,500,000 | 23,150,000 | 23,850,000 |
| | | | Unspecified Circuits/ Blankets | | | 2018 | 2019 | 2020 | 2021 | 2022 |
| UES Cap | DAB | 00 | Overhead Line Extensions | New Customer | | 68,340 | - | - | - | - |
| UES Seaco | DAB | 00 | Overhead Line Extensions | New Customer | | 69,965 | - | - | - | - |
| UES Seaco | DBB | 00 | Underground Line Extensions | New Customer | | 373,995 | - | - | - | - |
| UES Cap | DPB | 01 | Distribution Pole Replacement | New Customer | | 756,470 | - | - | - | - |
| UES Seaco | DPB | 01 | Distribution Pole Replacements | Reliability (Condition Replacement) | | 731,133 | - | - | - | - |
| UES Cap | DRB | 00 | Reliabilty Projects | Reliability Enhancement | | 220,405 | - | - | - | - |
| UES Seaco | DRB | 00 | Reliabilty Projects | Reliability Enhancement | | 439,106 | - | - | - | - |
| UES Cap | DRC | 00 | Reliabilty Projects, Carryover | Reliability Enhancement | | 33,094 | - | - | - | - |
| UES Cap | DAB | 20 | Overhead Line Extensions | New Customer | | - | 64,392 | - | - | - |
| UES Seaco | DAB | 20 | Overhead Line Extensions - New Projects | New Customer | | - | 67,613 | - | - | - |
| UES Cap | DBB | 20 | Underground Line Extensions | New Customer | | - | 152,433 | - | - | - |
| UES Seaco | DBB | 20 | Underground Line Extensions - New Projects | New Customer | | - | 362,152 | - | - | - |
| UES Cap | DRB | 20 | Reliability Projects | Reliability Enhancement | | - | 375,000 | - | - | - |
| UES Seaco | DRB | 20 | Reliability Projects, Unspecified | Reliability Enhancement | | - | 375,000 | - | - | - |
| UES Seaco | DRC | 20 | 3346 Line – Automatic Restoration Scheme | Reliability Enhancement | | - | 164,235 | - | - | - |
| UES Cap | DPB | 21 | Distribution Pole Replacement (REP) | Reliability (Condition Replacement) | | - | 737,927 | - | - | - |
| UES Seaco | DPB | 21 | Distribution Pole Replacements | Reliability (Condition Replacement) | | - | 713,279 | - | - | - |
| UES Seaco | DPB | 25 | Porcelain Cutout Replacements | | | - | 174,382 | - | - | - |
| UES Cap | DPB | 27 | Porcelain Cutout Replacements | Reliability Fault Prevention | | - | 174,382 | - | - | - |
| UES Cap | DPB | 30 | Porcelain Cutout Replacements | Reliability Fault Prevention | | - | 174,382 | - | - | - |
| UES Cap | DAB | 40 | Overhead Line Extensions | New Customer | | - | - | 81,146 | - | - |
| UES Seaco | DAB | 40 | Overhead Line Extensions - New Projects | New Customer | | - | - | 88,006 | - | - |
| UES Cap | DBB | 40 | Underground Line Extensions | New Customer | | - | - | 197,240 | - | - |
| UES Seaco | DBB | 40 | Underground Line Extensions - New Projects | New Customer | | - | - | 469,035 | - | - |
| UES Cap | DRB | 40 | Reliability Projects | Reliability Enhancement | | - | - | 375,000 | - | - |
| UES Seaco | DRB | 40 | Reliability Projects, Unspecified | Reliability Enhancement | | - | - | 375,000 | - | - |
| UES Cap | DPB | 41 | Distribution Pole Replacement (REP) | Reliability (Condition Replacement) | | - | - | 877,676 | - | - |
| UES Seaco | DPB | 41 | Distribution Pole Replacements | Reliability (Condition Replacement) | | - | - | 845,513 | - | - |
| UES Cap | DAB | 60 | Overhead Line Extensions | New Customer | | - | - | - | 83,742 | - |
| UES Seaco | DAB | 60 | Overhead Line Extensions - New Projects | New Customer | | - | - | - | 93,237 | - |
| UES Cap | DBB | 60 | Underground Line Extensions | New Customer | | - | - | - | 209,249 | - |
| UES Seaco | DBB | 60 | Underground Line Extensions - New Projects | New Customer | | - | - | - | 496,868 | - |
| UES Cap | DRB | 60 | Reliability Projects | Reliability Enhancement | | - | - | - | 375,000 | - |
| UES Seaco | DRB | 60 | Reliability Projects, Unspecified | Reliability Enhancement | | - | - | - | 375,000 | - |
| UES Cap | DPB | 61 | Distribution Pole Replacement (REP) | Reliability (Condition Replacement) | | - | - | - | 906,514 | - |
| UES Seaco | DPB | 61 | Distribution Pole Replacements | Reliability (Condition Replacement) | | - | - | - | 873,730 | - |
| UES Cap | DAB | 80 | Overhead Line Extensions | New Customer | | - | - | - | - | 85,360 |
| UES Seaco | DAB | 80 | Overhead Line Extensions - New Projects | New Customer | | - | - | - | - | 97,674 |
| UES Cap | DBB | 80 | Underground Line Extensions | New Customer | | - | - | - | - | 213,514 |
| UES Seaco | DBB | 80 | Underground Line Extensions - New Projects | New Customer | | - | - | - | - | 521,123 |
| UES Cap | DRB | 80 | Reliability Projects | Reliability Enhancement | | - | - | - | - | 375,000 |
| UES Cap | DPB | 81 | Distribution Pole Replacement (REP) | Reliability (Condition Replacement) | | - | - | - | - | 932,597 |
| UES Seaco | DPB | 81 | Distribution Pole Replacements | Reliability Enhancement | | - | - | - | - | 899,247 |
| | | | Unspecified Circuits/ Blankets Subtotal | | | 2,692,508 | 3,535,177 | 3,308,616 | 3,413,340 | 3,124,515 |
| | | | | | | | | | | |
| | | | Specific Circuit Projects | | | 2018 | 2019 | 2020 | 2021 | 2022 |
| UES Seaco | DPC | 01 | Circuit 19X3, Convert Newfields Rd, Exeter, (to provide service to Waste Water Treatment Plant) | Capacity | Mulit-year project (2017 - 2018) To serve new customer - Convert a portion of circuit from 4 kV to 13.8 kV and transfer to adjacent 13.8 kV circuit. | 42,110 | - | - | - | - |
| UES Cap | DPB | 02 | Manhole improvements MH 17 | Condition Replacement | | 237,338 | - | - | - | - |
| UES Seaco | DPB | 02 | Circuit 3H1 - Convert to 13.8 kV, Hampton Beach | Reliability Condition replacement | Eliminate 4 kV portion of substation | 168,622 | - | - | - | - |
| UES Seaco | DPC | 02 | Replace Seabrook Station Primary Metering | Capacity | Metering is limiting factor of subtransmission line. Replacing metering increases rating of subtransmission line | 73,277 | - | - | - | - |
| UES Cap | DPB | 03 | Rebuild Lowes Ave with Hendrix Construction | Reliability Fault Prevention | | 102,699 | - | - | - | - |
| UES Seaco | DPB | 03 | Circuits 3H2 and 3H3 - Convert to 13.8 kV, Hampton Beach | Reliability Condition replacement | Eliminate 4 kV portion of substation | 25,114 | - | - | - | - |
| UES Cap | DPB | 04 | Replace Direct Burried Cable Centerwood Dr. Concord | Reliability Fault Prevention | | 95,382 | - | - | - | - |
| UES Seaco | DPB | 04 | Convert and Transfer Portion of 43X1 to 6W2, Main Street, Kingston | Capacity | To serve new customer - Convert a portion of circuit from 4 kV to 13.8 kV and transfer to adjacent 13.8 kV circuit. | 171,578 | - | - | - | - |
| UES Seaco | DPB | 05 | Circuits 5H1/5H2 - Transfer to 5X3, Witch Lane, Plaistow | Reliability Condition replacement | Eliminate aging 4 kV substation transformer and equipment and transfer circuits to newer circuit | 172,041 | - | - | - | - |
| UES Seaco | DPC | 21 | Circuit 3H1 - Convert to 13.8 kV, Hampton Beach | Reliability Condition replacement | (Second year of multi-year proejct). Eliminate 4 kV portion of substation | - | 1,176,077 | - | - | - |
| UES Cap | DPB | 22 | 2H2 Spacer Cable Replacement | Reliability Condition replacement | | - | 217,986 | - | - | - |
| UES Seaco | DPB | 22 | Circuit 56X1 - Convert Route 125 | Reliability Enhancement | Allows remote switching of circuits following a fault on one of the lines or for planned system switching. This project works towards the master plan of establishing 34.5 kV circuit ties along Route 125 in Kingston and Plaistow. | - | 406,097 | - | - | - |
| UES Seaco | DPC | 22 | Circuit 3H2 and 3H3 - Convert to 13.8 kV | Reliability Condition replacement | (Second year of multi-year proejct). Eliminate 4 kV portion of substation | - | 216,389 | - | - | - |
| UES Cap | DPB | 23 | Build Circuit Tie between 8X3 and 8X5 | Reliability Enhancement | | - | 131,869 | - | - | - |
| UES Seaco | DPB | 23 | Circuit 3W4 - Convert O Street to 13.8 kV, Hampton Beach | Capacity | Load approaching Step down transformer rating | - | 175,521 | - | - | - |
| UES Seaco | DPC | 23 | Circuits 5H1/5H2 - Transfer to 5X3, Witch Lane, Plaistow | Reliability Condition replacement | (Second year of multi-year project) Eliminate aging 4 kV substation transformer and equipment and transfer circuits to newer circuit | - | 52,873 | - | - | - |
| UES Cap | DPB | 24 | Circuit 13W3: Replace North Water St Fuse with Sectionalizer | Reliability Enhancement | | - | 11,833 | - | - | - |
| UES Seaco | DPB | 24 | Circuit 6W1 - Install Regulator Burnt Swamp Road, East Kingston | Voltage | Low voltage expected on high load | - | 54,350 | - | - | - |
| UES Cap | DPB | 25 | Manhole improvements MH6&7 | Condition Replacement | | - | 130,412 | - | - | - |
| UES Cap | DPB | 26 | Install Interrupter in MH22 | Reliability Enhancement | | - | 25,328 | - | - | - |
| UES Seaco | DPB | 26 | Replace 3347A and 3347B Reclosers at 3347 Line Tap, Stratham | Reliability Condition replacement | Part of replacment program for known concern with particular protective equipment | - | 237,515 | - | - | - |
| UES Cap | DPB | 28 | 374X1 Spacer Cable Replacement | Reliability Condition replacement | | - | 47,924 | - | - | - |
| UES Seaco | DPB | 28 | Circuit 19H1 - Transfer to 27X1, Drinkwater Rd., Kensington | Reliability Condition replacement | Transformer needs to be replaced/removed due to condition. This project is less costly than purchasing new transformer | - | 192,126 | - | - | - |
| UES Cap | DPB | 29 | 396X1 Tap - Install Recloser | Reliability Enhancement | | - | 96,733 | - | - | - |
| UES Cap | DPB | 31 | Install Conduit and URD Cable between Pads 2 and 3 Middlebury St. Concord | Reliability Enhancement | | - | 62,453 | - | - | - |
| UES Cap | DPB | 33 | Perform Cable Injection Fairfield St. Concord | Reliability Fault Prevention | | - | 261,807 | - | - | - |
| UES Cap | DPB | 34 | Replace Direct Buried URD Cable Rocky Point Dr, Bow | Reliability Fault Prevention | | - | 94,993 | - | - | - |
| UES Cap | DPB | 42 | Replace Direct Buried URD Cable Rocky Point Dr, Bowphase 2 | Reliability Fault Prevention | | - | - | 175,822 | - | - |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| UES Seaco | DPB | 42 | Timberlane S/S - Installation of Motor Operated Switches with SCADA Control | Reliability Enhancement | Allows remote switching of circuits following a fault on one of the lines or for planned system switching. | - | - | 55,879 | - | - |
| UES Cap | DPB | 43 | 22W2 Spacer Cable Replacement | Reliability Condition replacement | | - | - | 111,630 | - | - |
| UES Cap | DPB | 44 | 14X3 Spacer Cable Replacement | Reliability Condition replacement | | - | - | 79,121 | - | - |
| UES Cap | DPB | 45 | Install Conduit and URD cable Middlebury St. Concord | Reliability Fault Prevention | | - | - | 49,482 | - | - |
| UES Cap | DPB | 62 | Circuit 18W2: Transfer load to 7W3 and Install Regulation on 7W3 | Capacity | Transfer load from 18W2 to 7W3 to reduce load and defer thermal overload on 18W2 | - | - | - | 140,076 | - |
| | | | | | | | | | | |
| | | | Circuit Specific Project Subtotal | | | 1,088,161 | 3,592,286 | 471,934 | 140,076 | - |
| | | | | | | | | | | |
| | | | Specific Substation Projects | | | 2018 | 2019 | 2020 | 2021 | 2022 |
| UES Cap | SPB | 01 | Replace Failed RTU at Penacook | Condition Replacement | Replace Aged equipment and rebuild to new design criteria | 27,574 | - | - | - | - |
| UES Seaco | SPB | 01 | Hampton Beach - 13kV Additions and 4kV Removals | Reliability Condition replacement | Eliminate 4 kV portion of substation | 311,413 | - | - | - | - |
| UES Cap | SPC | 01 | West Concord - Replace 2H1 Breaker | Condition Replacement | | 233,255 | - | - | - | - |
| UES Seaco | SPB | 02 | Substation Fence Replacement | Condition Replacement | Security/safety related | 65,530 | - | - | - | - |
| UES Cap | SPC | 02 | Bridge Street - Replace 35kV Line Relaying & Modify RTU | System Protection | New System configuration requires more sensitive protection coordination | 359,657 | - | - | - | - |
| UES Seaco | SPB | 03 | Install Stone in Various Substations | Condition Replacement | Security/safety related | 26,560 | - | - | - | - |
| UES Seaco | SPB | 21 | Guinea - 3112, 3165, 3172 Relay & Meter Modifications | Condition Replacement | To Correct protection/metering condition | - | 89,830 | - | - | - |
| UES Seaco | SPC | 21 | Hampton Beach - 13kV Additions and 4kV Removals | Reliability Condition replacement | Eliminate 4 kV portion of substation (second year of mulit-year project) | - | 778,255 | - | - | - |
| UES Cap | SPB | 22 | AMI Cell Modem Installations | Condition Replacement | | - | 36,983 | - | - | - |
| UES Seaco | SPB | 22 | Install Stone in Substations | Condition Replacement | Security/safety related | - | 51,813 | - | - | - |
| UES Cap | SPB | 23 | Gulf St. Substation upgrade | Condition Replacement | Replace Aged equipment and rebuild to new design criteria | - | 181,511 | - | - | - |
| UES Seaco | SPB | 23 | Guinea - Upgrade Site Communications | Reliability Condition replacement | | - | 85,383 | - | - | - |
| UES Cap | SPB | 24 | West Concord - Replace RTU and Upgrade Equipment | Condition Replacement | Replace Aged equipment and rebuild to new design criteria | - | 248,212 | - | - | - |
| UES Seaco | SPB | 24 | Kingston - Modifications & Additions | Operational enhancement | | - | 69,422 | - | - | - |
| UES Cap | SPB | 25 | West Portsmouth Street - Replace RTU and Upgrade Equipment | Condition Replacement | Replace Aged equipment and rebuild to new design criteria | - | 248,212 | - | - | - |
| UES Seaco | SPB | 25 | AMI Cell Modem Installations | Reliability Condition replacement | | - | 36,983 | - | - | - |
| UES Cap | SPB | 26 | Replace Fence at Gulf St. Substation | Condition Replacement | Security/safety related | - | 68,665 | - | - | - |
| UES Cap | SPB | 27 | Substation Fence Replacement | Condition Replacement | Security/safety related | - | 96,336 | - | - | - |
| UES Seaco | SPB | 41 | Substation Fence Replacement | Condition Replacement | Security/safety related | - | - | 109,342 | - | - |
| UES Cap | SPB | 42 | Replace the 34 OCB at Bridge Street | Reliability Condition replacement | | - | - | 166,431 | - | - |
| UES Cap | SPB | 43 | Gulf St. Substation upgrade - Carry-over | Condition Replacement | Replace Aged equipment and rebuild to new design criteria | - | - | 201,418 | - | - |
| UES Cap | SPB | 44 | Replace the 0374 OCB at Bridge Street | Condition Replacement | | - | - | 166,431 | - | - |
| UES Cap | SPB | 45 | Substation Fence Replacement | Condition Replacement | Security/safety related | - | - | 109,342 | - | - |
| UES Seaco | SPB | 61 | Install Stone in Substations | Condition Replacement | Security/safety related | - | - | - | 59,526 | - |
| UES Cap | SPB | 62 | Install Stone in Substations | Condition Replacement | Security/safety related | - | - | - | 59,526 | - |
| UES Seaco | SPB | 62 | Substation Fence Replacement | Condition Replacement | Security/safety related | - | - | - | 110,251 | - |
| UES Cap | SPB | 63 | Terrill Park - Replace RTU and Upgrade Equipment | Condition Replacement | Replace Aged equipment and rebuild to new design criteria | - | - | - | 224,621 | - |
| UES Cap | SPB | 64 | Pleasant Street - Replace RTU and Upgrade Equipment | Condition Replacement | Replace Aged equipment and rebuild to new design criteria | - | - | - | 224,621 | - |
| UES Cap | SPB | 65 | Replace the 0317 OCB at Penacook | Condition Replacement | Replace Aged equipment and rebuild to new design criteria | - | - | - | 168,093 | - |
| UES Cap | SPB | 82 | Replace the 35 OCB at Bridge Street | Condition Replacement | Replace Aged equipment and rebuild to new design criteria | - | - | - | - | 168,097 |
| UES Cap | SPB | 83 | Gulf Street - Replace RTU and Upgrade Equipment | Condition Replacement | Replace Aged equipment and rebuild to new design criteria | - | - | - | - | 331,851 |
| UES Cap | SPB | 84 | Langdon Avenue - Replace RTU and Upgrade Equipment | Condition Replacement | Replace Aged equipment and rebuild to new design criteria | - | - | - | - | 331,851 |
| | | | Substation specific project subtotal | | | 1,023,989 | 1,991,605 | 752,964 | 846,638 | 831,799 |

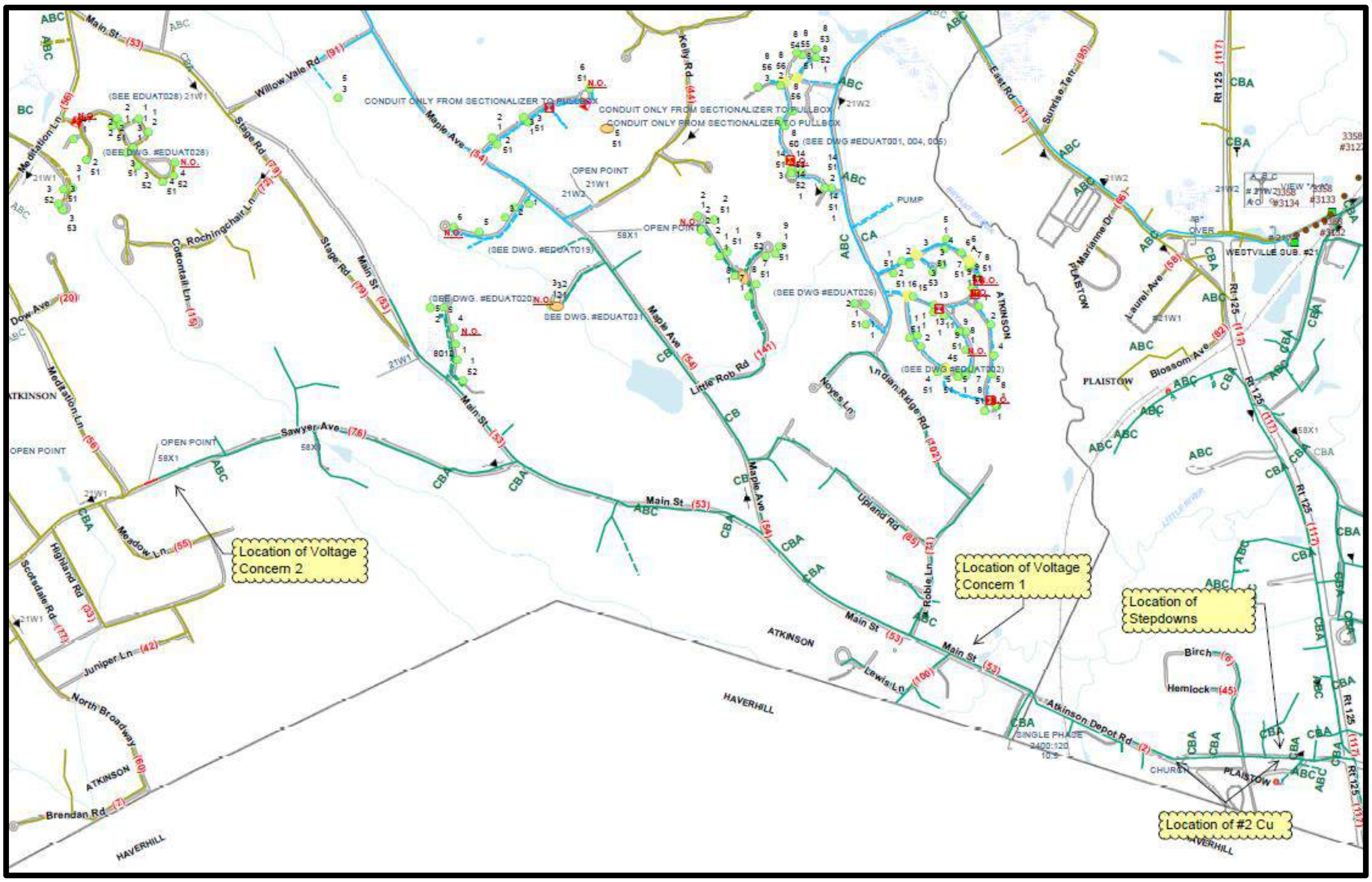
**Constraint:** Circuit 58X1 – Wentworth Ave

- Wentworth Avenue 500 kVA stepdown loading
  - Low side 200QA fuse loading
- Wentworth Avenue #2 Cu conductor loading
- Low voltage prior to regulators
- Low voltage at the end of line

**Year Needed:** 2024 **Area Load in Need Year:** 1,500 KVA

**Annual Growth Rate:** 1.15%

**Map of Area:** Wentworth Ave, Plaistow / Main Street, Atkinson




**Conventional Alternative:** Rebuild and Convert to 34.5 kV

The previously identified project is to rebuild and convert approximately 4,500 feet of three-phase line including laterals. This will include the installation of two new banks of stepdown transformers and the relocation of the existing voltage regulators.

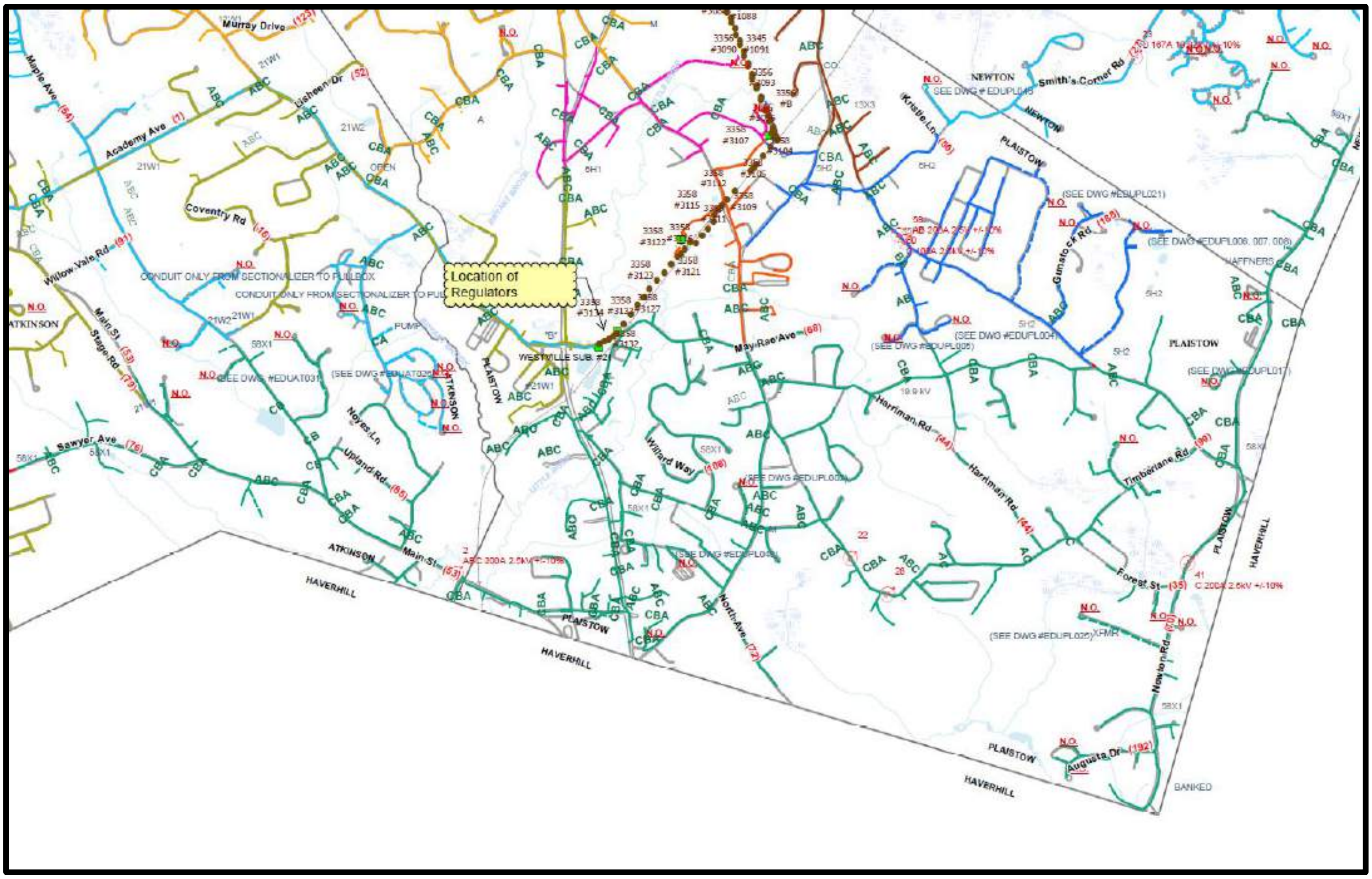
Estimated Cost: $240,000 (2017 dollars w/o overheads and including transformers)

**Constraint:** Circuit 58X1 – Westville Road Tap
- Voltage regulator loading

**Year Needed:** 2028 **Area Load in Need Year:** 14,000 KVA

**Annual Growth Rate:** 1.15%

**Map of Area:** Circuit 58X1, Plaistow/Atkinson/Newton




## **Conventional Alternative 1:** **Upgrade Regulators**

Conventional alternative one is to replace the existing voltage regulators with new units. This will require the existing regulator structure to be replaced.

Estimated Cost: $180,000 (2017 dollars w/o overheads)

**Conventional Alternative 2:** **Rebuild and Convert Portion of 5X3 and Offload 58X1**

Conventional alternative two is to rebuild (including reconductoring) and convert approximately 2,500 feet of three-phase mainline including laterals.

In addition to addressing the identified loading concern this project creates a 34.5 kV circuit tie between 5X3 and 58X1, that would be used to restore load for faults on 5X3, 58X1 and the 3358 line.

Estimated Cost: $210,000 (2017 dollars w/o overheads and including transformers)

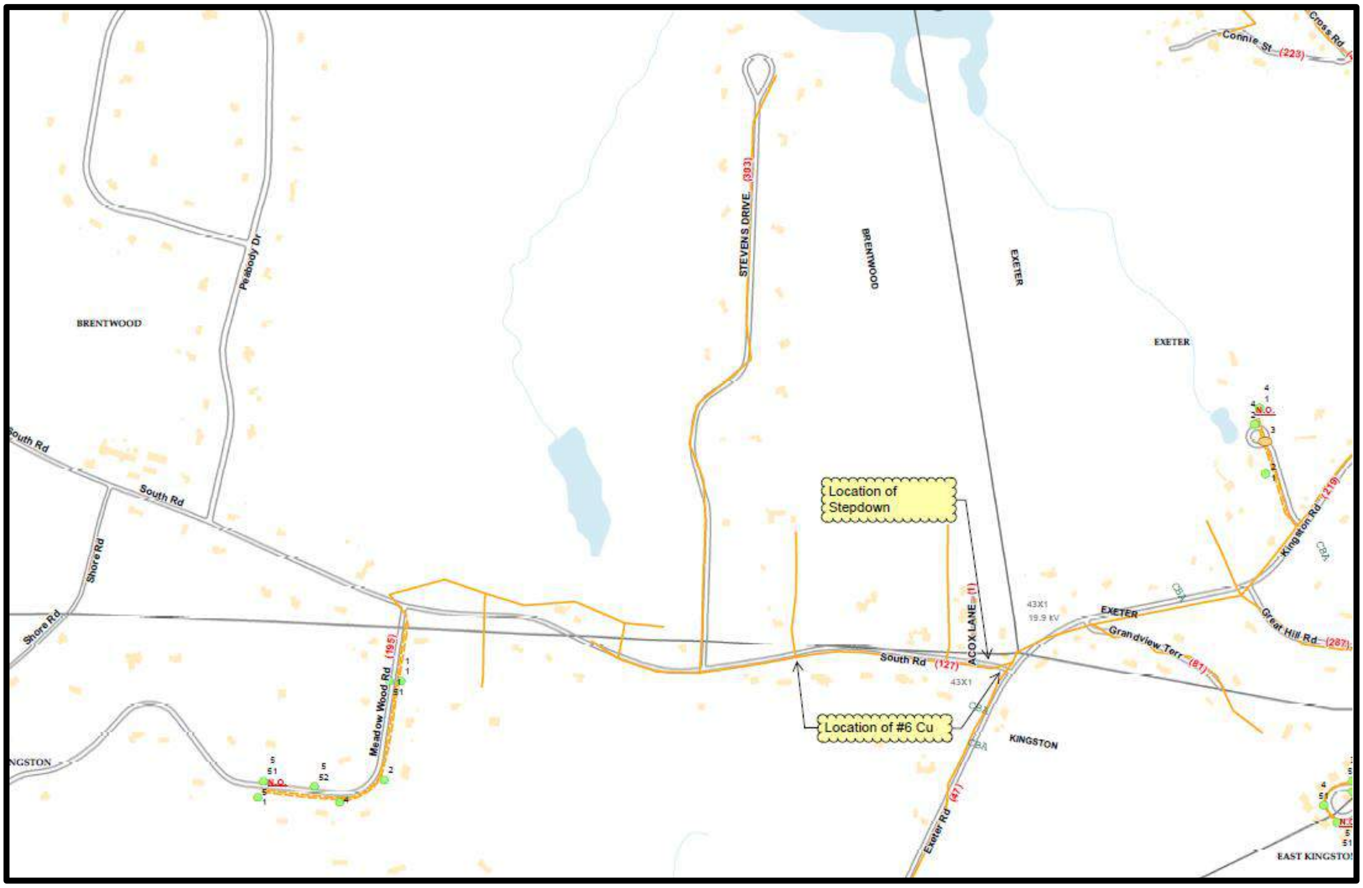
**Constraint:** Circuit 43X1 – South Road

- South Road 250 kVA stepdown loading
- South Road #6 Cu conductor loading

**Year Needed:** 2029 **Area Load in Need Year:** 275 KVA

**Annual Growth Rate:** 0.95%

**Map of Area:** South Road, Kingston/Brentwood




**Conventional Alternative:** Upgrade Stepdown and Reconductor

The previously identified project is to replace the existing stepdown transformer with a larger unit and reconductor approximately 1,000 feet of single-phase line.

Estimated Cost: $40,000 (2017 dollars w/o overheads and including transformers)

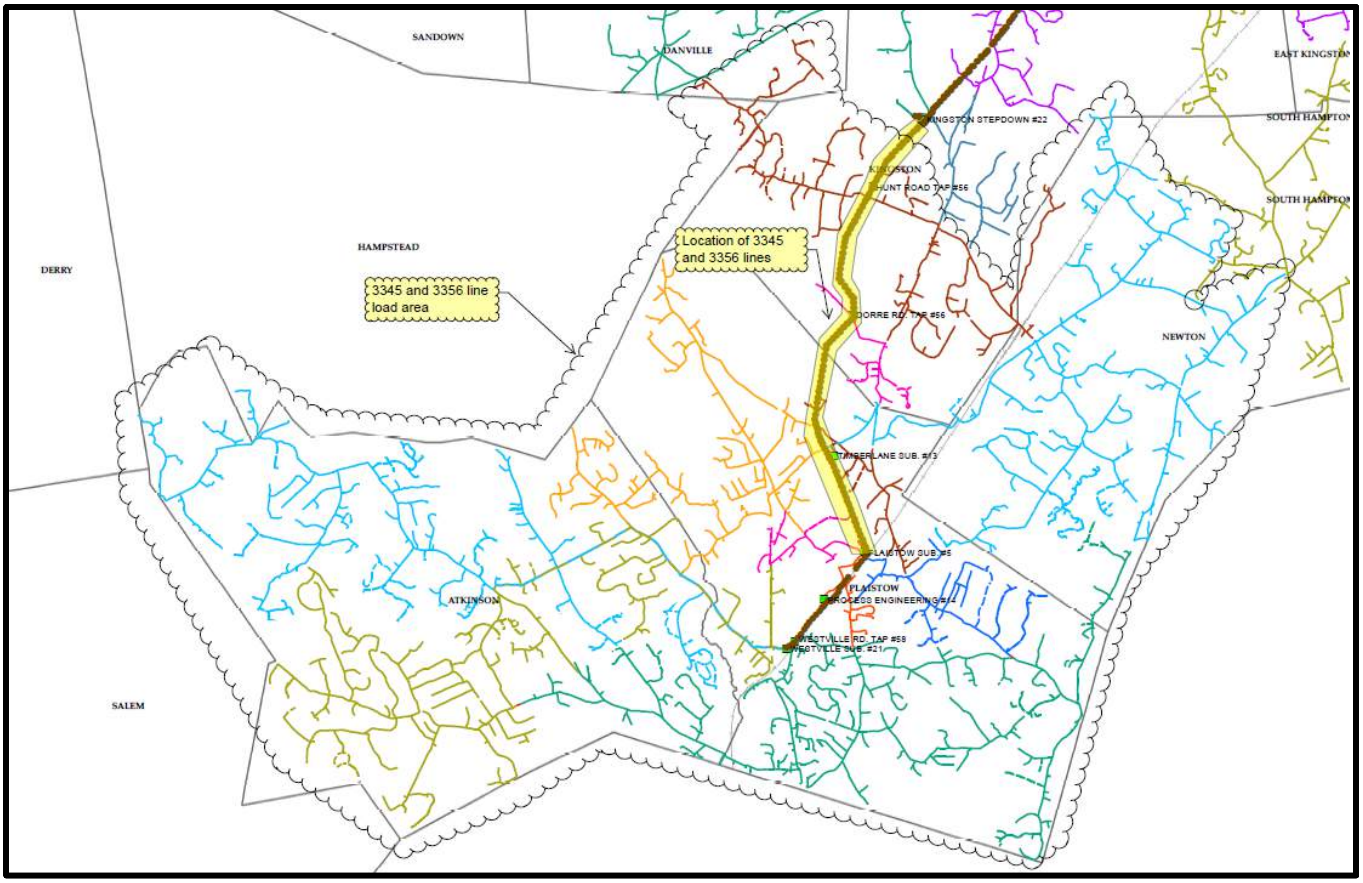
**Constraint:** 3345/3356 Lines

- 3345/3356 line loading for loss of the other line

**Year Needed:** 2028 **Area Load in Need Year:** 41,000 KVA

**Annual Growth Rate:** 0.9%

**Map of Area:** Atkinson/Plaistow and portions of Kingston/Newton




**Conventional Alternative 1:** **Build New Line from Kingston Substation to Plaistow Substation**

Conventional alternative one is to construct a new line in the 3345/56 right-of-way from Kingston substation to Plaistow substation. This will require the construction of a new 34.5 kV line terminal at Kingston and modifications to the 3358 tap at Plaistow.

Estimated Cost: $2,650,000 (2017 dollars w/o overheads)

**<u>Conventional Alternative 2:</u>** **Reconductor the 3345 and 3356 Lines**

Conventional alternative two is to reconductor the 3345 and 3356 lines from Kingston to Hunt Road in 2028 and Hunt Road to Timberlane in 2030.

Estimated Cost (2023): $650,000 (2017 dollars w/o overheads)
Estimated Cost (2029): <u>$1,600,000 (2017 dollars w/o overheads)</u>
Estimated Cost (Total): $2,250,000 (2017 dollars w/o overheads)

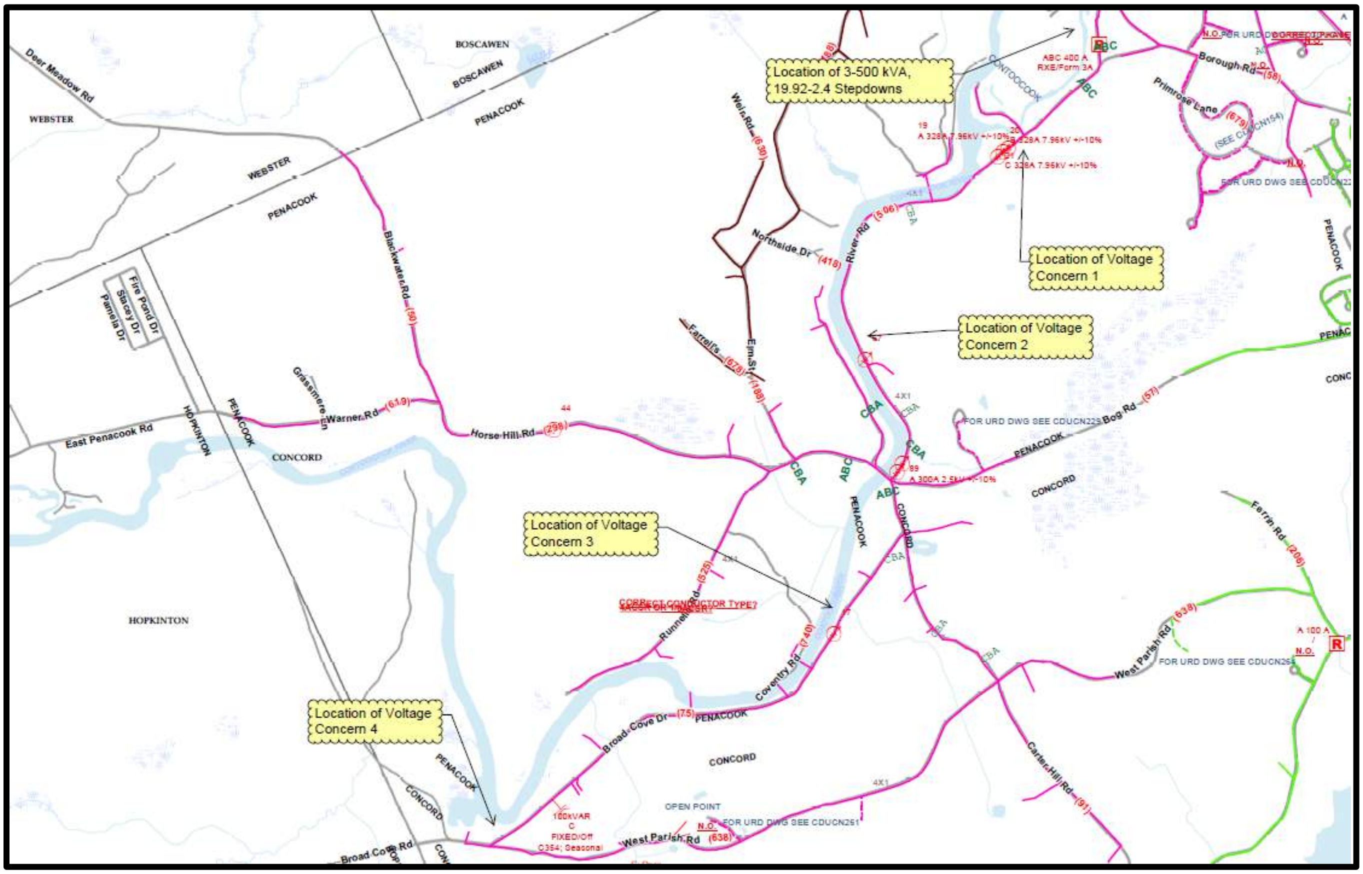
**Constraint:** Circuit 4X1 – River Road

- Low voltage at various locations along river road

**Year Needed:** 2023 **Area Load in Need Year:** 1,000 KVA

**Annual Growth Rate:** 0.75%

**Map of Area:** River Road/Broad Cove Road, Concord




**Conventional Alternative:** Rebuild and Convert to 34.5 kV

The previously identified project is to rebuild and convert approximately 5,500 feet of three-phase line including laterals. This will include the installation of a new bank of stepdown transformers and the relocation of several voltage regulators.

Estimated Cost: $325,000 (2017 dollars w/o overheads and including transformers)

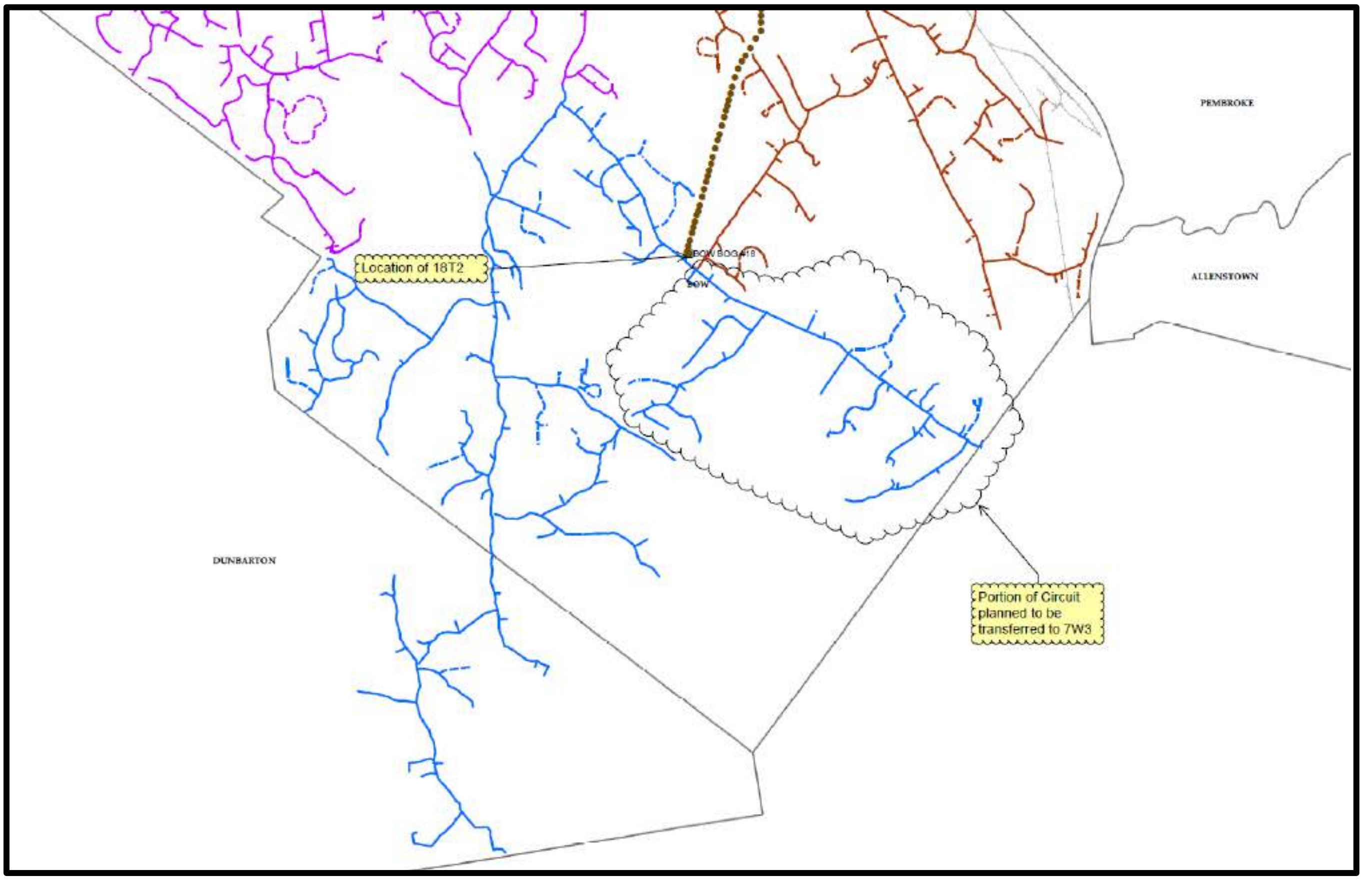
**Constraint:** Bow Bog Substation

- 18T2 Substation Transformer Loading

**Year Needed:** 2023 **Area Load in Need Year:** 3,500 KVA

**Annual Growth Rate:** 0.70%

**Map of Area:** Southern Area of Bow




**Conventional Alternative:** Transfer Load / Add Additional Transformer Capacity

The previously identified project is to transfer load from 18W2 to 7W3 and install distribution voltage regulators in 2023.

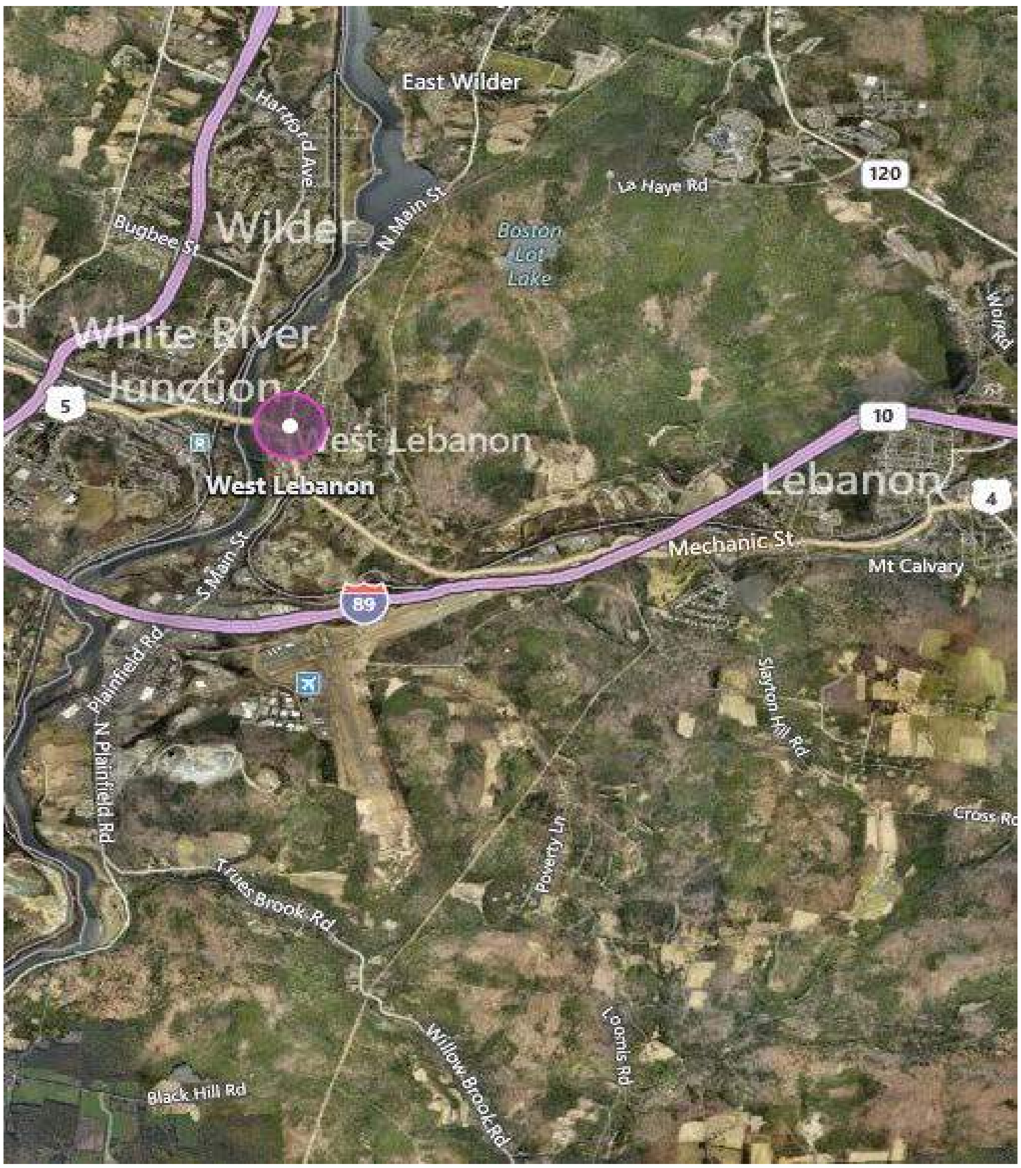
This load transfer is expected to cause loading concerns of 7T1 at Bow Junction substation as early as 2029. At which time additional transformer capacity will need to be installed at Bow Bog, Iron Works or Bow Junction substations.

Estimated Cost (2023): $75,000 (2017 dollars w/o overheads)
Estimated Cost (2029): $650,000 (2017 dollars w/o overheads)
Estimated Cost (Total): $725,000 (2017 dollars w/o overheads)

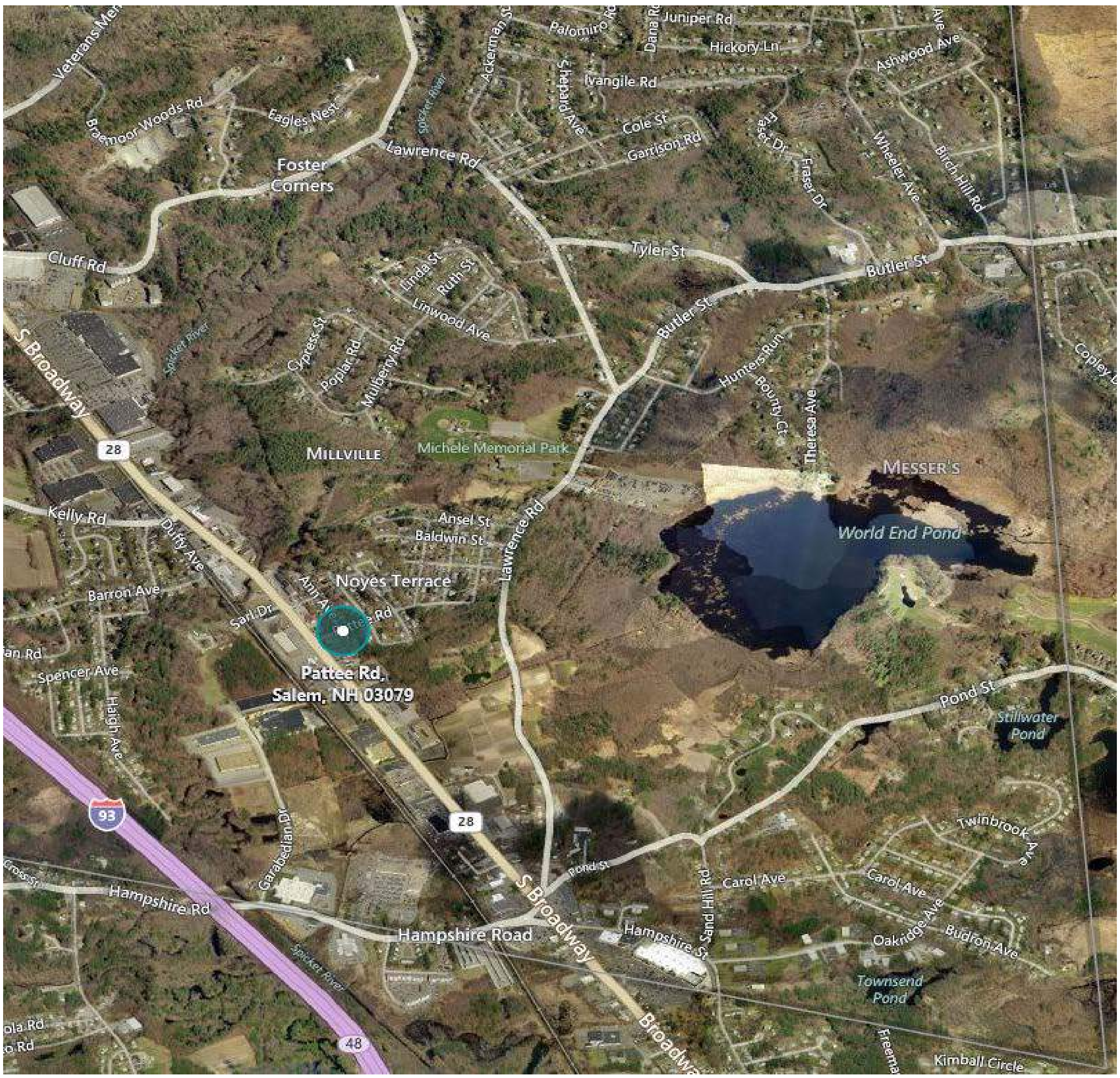
| Project_Description | Budget Year | Estimate | Budget Class | Planning Criteria Violation | Benefits |
|---|---|---|---|---|---|
| Michael Ave Dist Line | 2022 | $1,600,000 | E - Reliability | 12L1 No. Customers served over 2,500 / less than 3 feeder ties | Resolves criteria violation and improves reliability for towns of Alstead, Acworth, Langdon and Marlow. |
| Michael Ave Dist Sub | 2022 | $325,000 | E - Reliability | 12L1 No. Customers served over 2,500 / less than 3 feeder ties | Resolves criteria violation and improves reliability for towns of Alstead, Acworth, Langdon and Marlow. |
| Install 39L4 Distribution Slayton Hill | 2020 | $315,000 | E - Load Related | 11L1 Loading above 75% of summer normal / 11L2 loading above 75% / 11L2 less than 3 feeder ties | Resolves criteria violation and improves reliability for town of West Lebanon. |
| Install 39L4 Feeder Position Slayton Hill | 2020 | $325,000 | E - Load Related | 11L1 Loading above 75% of summer normal / 11L2 loading above 75% / 11L2 less than 3 feeder ties | Resolves criteria violation and improves reliability for town of West Lebanon. |
| Mt Support Sub - 16L7 Dist Sub | 2020 | $450,000 | E - Reliability | None | Reliability improvement for south Hanover and west Lebanon. |
| Mt Support Sub - 16L7 Dist Line | 2020 | $750,000 | E - Reliability | None | Reliability improvement for south Hanover and west Lebanon. |
| Reconductor 10L4 Pattee Rd | 2022 | $550,000 | E - Load Related | 10L1 loading above 75% of summer normal. Contingency loading above summer emergency rating. | Resolves criteria violation and contingency risk for customers served from south east Salem. |
| Install Lebanon 1L2 Feeder Tie - Plainfield | 2022 | $1,300,000 | E - Reliability | None | Reliability improvement for the towns of Plainfield and Surry. |
| Install Vilas Bridge 12L1-12L2 Feeder Tie | 2022 | $800,000 | E - Load Related | 12L2 contingency loading above 16 MWhr | Reliability improvement for the town of Walpole. |

## Non-Wires Alternative Pilot Program Development

| | |
|---|---|
| **Pilot Location 1** | West Lebanon NH |
| **Project Description** | Install new Slayton Hill 39L4 Distribution Feeder |
| **Engineering Start Date – Project Completion Date** | 2020 - 2021 |
| **Criteria Violation** | Craft Hill 11L1 Loading above 75% of summer normal / 11L2 loading above 75% of summer normal / 11L2 less than 3 feeder ties |
| **Benefits of Planned Wires Upgrade** | Resolves criteria violation and improves reliability for the town of West Lebanon. |
| **Estimated Costs (Investment Grade)** | $640,000 |
| **Area load in need year** | 1,500kVA |
| **Annual growth rate** | 0.6% |



| Pilot Location 2 | South-East Salem NH |
|---|---|
| **Project Description** | Reconductor Baron Ave 10L4 along Pattee Rd |
| **Engineering Start Date – Project Completion Date** | 2019-2020 |
| **Criteria Violation** | Salem Depot 10L1 conductor loading above 75% of summer normal. Contingency loading on conductor above summer emergency rating. |
| **Benefits of Planned Wires Upgrade** | Resolves criteria violation and contingency risk for customers located at south east Salem NH. |
| **Estimated Costs (Investment Grade)** | $550,000 |
| **Area load in need year** | 1,000kVA |
| **Annual growth rate** | 0.6% |



## Eversource Project List

11/06/2017

Project list does not include "annuals" for basic day-to-day operations (e.g. connecting customers, emergency repairs, NHDOT relocations, etc.), projects underway with 2018 ISD's, obsolete asset replacement programs (e.g. oil circuit breaker replacements, porcelain replacement, reject pole replacement, etc), distribution automation programs.

Projects planned due to asset condition and/or existing overload are not candidates for non-wires alternatives.

| Project Description | Year Planned Start/Finish | Criteria Violation | Benefit of Upgrade | Budget (Preliminary) Estimate ($1,000's) (2018 forward) |
|---|---|---|---|---|
| Pemigewasset S/S - Upgrade 20 MVA transformer (1956) | 2018/2019 | Overload under basecase condition. | Improve reliability, prevent failure of transformer. Provide additional transformer capacity to allow backfeed of circuit ties for reliabilty improvement. | 4000 |
| Monadnock S/S - Upgrade 20 MVA transformer (1951), upgrade substation with low side transformer breakers, replace obsolete relays, incorporate automatic bus restoral scheme. | 2018/2019 | Basecase overload, asset condition. | Address transformer loading, addresses substandard substation design, addresses insufficient transformer capacity to backup circuit ties, addresses aging assets. | 4000 |
| Portsmouth S/S - Upgrade existing transfomer and add a second transformer. | 2018/2019 | Required to retire Resistance S/S due to asset condition. (constructed circa 1950) | Allows retirement of Resistance S/S, additional transformer capacity for improved reliability. | 7500 |
| Dover S/S - Upgrade existing transformers (1972), construct control house, replace obsolete relays. | 2018/2020 | Transformer loading, asset condition. | Additional transformer capacity to support both line and substation contingencies. Address obsolete equipment. | 11000 |
| White Lake - Upgrade existing 28 MVA transformers (1963), replace aging infrastructure. | 2018/2020 | Transfomer loading, asset condition. | Additional transformer capacity to support both line and substation contingencies. Address obsolete equipment. | 11000 |
| River Road S/S - Upgrade S/S due to Industrial Park projected growth. | 2018/2019 | Transformer loading | Meet customer demand, provide additional transformer capacity for circuit ties. | 2500 |
| Millyard S/S Nashual - Rebuild 1940's vintage substation. | 2017/2019 | Asset Condition. | Addresses asset condition and operational issues. | 7000 |
| Twombley S/S - Rebuild at 12.47 kV with 12.5 MVA | 2017/2018 | Asset Condition, Required to retire Signal St S/S. | Reliability, creates 12kV circuit ties with capacity. | 1500 |
| Rochester 4kV Conversion | 2018/2020 | Asset Condition, Required to retire Signal St S/S. | Reliability, creates 12kV circuit ties with capacity. | 6000 |
| Brook St S/S - 13TR1 Replacement (Switchgear (1961)) | 2019/2020 | Asset Condition | Reliability, addresses asset condition. | 2200 |
| 328 Line Reconductor | 2018 | Asset Condition, required to retire Greggs Distribution S/S (1949) | Reliability, addresses asset condition. | 2000 |

| Project Description | Year Planned Start/Finish | Criteria Violation | Benefit of Upgrade | Budget (Preliminary) Estimate ($1,000's) (2018 forward) |
|---|---|---|---|---|
| Rye Area 4kV Conversion | 2018/2019 | Asset Condition, required to retire Rye 4kV transformer (1956) | Reliability, addresses asset condition and provides 12kV circuit ties in area. | 1900 |
| Old Amherst Rd 23X5, 23X6, Convert existing three phase 4.16 kV beyond step transformers on Route 13 in Mont Vernon to three phase 34.5 kV to provide a more reliable and robust feed to the Town of Mont Vernon. | 2019 | Reliability Worst Performing Circuit List | Reliability | 1000 |
| ROW System Hardening/Reconductoring - 3614 - Eliminate 2.25 miles of 266 6/7 conductor P 79 to N.O. at Hanover St S/S<br><br>Replace deficient poles on ROW Lines | 2018 | Asset Condition, Reliability | Addresses asset condition, reliability. | 2000 |
| Circuit Tie Construction<br>4W1 to W185 in Keene<br>3178X to 3178X3 Chestnut Hill<br>3177X1 to 3177X3 Nashua<br>360X5 to 322X10 New Boston | 2018 | Reliability Worst Performing Circuit List | Reliability - Provides circuit back up to radial circuits. | 5000 |
| Weirs S/S Rebuild | 2020/2021 | Loading on Black Brook, Reliability | Provides backup to Black Brook Transformer. | 3000 |
| Meetinghouse Rd S/S 3W2 Transformer Upgrade | 2021 | Overload on 3W2 Transformer | Reliability, additional transformer capacity to backup Meetinghouse Rd 3W1 Transformer. | 2000 |

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

| | | |
|---|---|---|
| In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for **DTE ELECTRIC COMPANY** to fully comply with Public Act 295 of 2008, as amended by Public Act 342 of 2016. | ) ) ) ) ) ) ) | Case No. U-18262 |

At the April 12, 2018 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Sally A. Talberg, Chairman
Hon. Norman J. Saari, Commissioner
Hon. Rachael A. Eubanks, Commissioner

## ORDER APPROVING SETTLEMENT AGREEMENT

On June 29, 2017, DTE Electric Company (DTE Electric) filed an application, with supporting testimony and exhibits, requesting approval of its energy waste reduction (EWR) plan and authority to implement EWR surcharges.

A prehearing conference was held on August 15, 2017. DTE Electric, the Natural Resources Defense Council, National Housing Trust, the Association of Businesses Advocating Tariff Equity (ABATE), the Residential Customer Group, and the Commission Staff (collectively, the parties) participated in the proceeding. A hearing was held on December 14, 2017, during which the testimony of the parties was bound into the record and exhibits were admitted into evidence. On March 20, 2018, the parties, excluding ABATE, submitted a settlement agreement resolving all issues in the case. On March 22, 2018, ABATE filed a statement of non-objection to the settlement agreement.

The Commission has reviewed the settlement agreement and finds that the public interest is adequately represented by the parties who entered into the settlement agreement. The Commission further finds that the settlement agreement is in the public interest, represents a fair and reasonable resolution of the proceeding, and should be approved.

THEREFORE, IT IS ORDERED that:

A. The settlement agreement, attached as Exhibit A, is approved.

B. DTE Electric Company is authorized to implement the surcharges set forth in the tariff sheets attached as Attachment F to the settlement agreement until new rates are approved in the company's next energy waste reduction plan filing.

C. Any over or underrecovery resulting from the surcharges shall be reflected in DTE Electric Company's next energy waste reduction plan reconciliation proceeding beginning balance.

D. Within 30 days, DTE Electric Company shall file tariff sheets consistent with this order and the settlement agreement.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

By its action of April 12, 2018.

________________________________
Kavita Kale, Executive Secretary

**EXHIBIT A**

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for **DTE ELECTRIC COMPANY** to fully comply with Public Act 295 of 2008, as amended by Public Act Act 342 of 2016 | ) ) ) ) ) ) ) | Case No. U-18262 |

**STIPULATION AND SETTLEMENT AGREEMENT**

Pursuant to Section 78 of the Administrative Procedures Act of 1969 ("APA"), as amended, MCL 24.278 and Rule 333 of the Rules of Practice and Procedure before the Michigan Public Service Commission ("MPSC" or "Commission"), the undersigned parties agree as follows:

WHEREAS, This Stipulation and Settlement Agreement ("Settlement Agreement") between DTE Electric Company ("DTE"), Natural Resources Defense Council ("NRDC"), National Housing Trust ("NHT"), the Residential Customer Group ("RCG"), the Association of Business Advocating Tariff Equity ("ABATE") and the Michigan Public Service Commission Staff ("Staff"), (collectively, the "Parties") is intended by the Parties as a final settlement and satisfaction of all issues before the Commission in the biennial review of DTE's Electric's Energy Waste Reduction Plan ("EWR Plan").

WHEREAS, On March 28, 2017, the Commission issued an Order in Case No. U-18262 requiring DTE Electric Company ("DTE Electric") or the "Company" to file its energy waste reduction plan by July 3, 2017.

WHEREAS, DTE Electric filed its application, with supporting testimony and exhibits, requesting approval of its EWR Plan on June 29, 2017 pursuant to the Commission's Order and the requirements of Act 295, as amended by Act 342.

WHEREAS, on July 14, 2017, the Commission directed DTE Electric to publish a notice of hearing in newspapers of general circulation in DTE Electric's service territory. A prehearing conference was conducted on August 15, 2017 at which a procedural schedule was adopted, and the Commission Staff, NRDC, NHT, RCG, and DTE Electric appeared as the parties participating in this case. The parties subsequently stipulated to the intervention of ABATE on October 6, 2017.

WHEREAS, the Parties have agreed to enter into a full settlement of this case, and request that the Commission enter an order accepting and approving DTE Electric's EWR Plan subject to the modifications as set forth in this agreement.

NOW THEREFORE, for purposes of settlement of case U-18262, the Parties agree as follows:

1. The parties agree that the Company's filed 2018-2019 EWR Plan should be approved in its entirety except as modified by this Settlement Agreement and the attachments to this Settlement Agreement.

2. Low-Income Programs. Collectively, DTE Electric and DTE Gas will increase investment in the Company's Energy Efficiency Assistance (EEA) Program by Five Million Dollars ($5,000,000) within the 2018-2019 Plan for the purposes of targeting low-income customers in arrears. At a minimum, One Million Dollars ($1,000,000) of the increased investment will occur in 2018; the remaining balance will be invested in 2019. The parties also agree that Company will implement the measures outlined in Attachment A to target low-income customers in arrears. DTE Electric will perform a study beginning in 2019 to evaluate the impacts of the EEA program enhancement on low income customers in arears.

3. Multi-Family Low-Income Programs. Collectively, DTE Electric and DTE Gas will increase multi-family low-income spend by $250,000 in 2018 for a total of $2,195,000 exclusive of pilot funding, and $3,000,000 in 2019 for a total of $4,955,000 exclusive of pilot

funding. The parties agree that DTE Electric will display its multi-family low-income investments as individual line items in the Company's EWR plans and reconciliations as set forth in Attachment B. DTE Electric will also implement the Multi-Family Low-Income Program pilot enhancements set forth on Attachment C.

4. Performance Incentive Mechanism. The metrics associated with the Performance Incentive Mechanism (PIM) will be as set forth in Attachment D of this Settlement Agreement. The parties agree that the metrics under the PIM are primarily based on lifetime savings targets and secondarily on low-income spend and low-income multi-family assessments.

5. Non-Wires Alternative. DTE Electric will implement a Non-Wires Alternative pilot that facilitates an evaluation of the cost-effectiveness impact of EWR on the scope of the Company's distribution system capital investment project. EWR pilot funding will be used to implement EWR measures in a Non-Wires Alternative pilot program. The EWR pilot is part of the Company's larger Non-Wires Alternative initiative that is still being developed. The EWR Non-Wires Alternative pilot is outlined in Attachment E.

6. Behavior Savings. DTE Electric will gradually reduce the behavior savings as a percentage of the residential portfolio by 3% each year beginning in 2019 to reach 15% by 2021. DTE Electric will include all annual, recurring evaluation expenditures for behavior-based programs in benefit/cost calculations so that the programs can provide the means to evaluate and compare programming options. To distinguish between measure incentives and program education costs, DTE Electric will provide clarity, where possible, in the annual reconciliation specifically around Home Energy Consultation, On-Line Energy Audit, and Business Energy Consultation.

7. Light Emitting Diodes Net-to-Gross. In 2018, DTE Electric will reduce the standard and reflector Light Emitting Diodes ("LED") Net-to-Gross ("NTG") factors in the Residential Energy Star Products Program from 0.92 to 0.90. The Company will continue its

annual third-party evaluation studies. The parties agree that the standard and reflector LED NTG in its Residential Energy Star Products Program for 2019 will be assessed in 2018, as appropriate, based on the judgment of DTE's evaluators. Such judgment shall take into account the results of the program year 2017 evaluation as well as any expected changes in market conditions between 2017 and 2019. DTE's evaluators may consider multiple research approaches to inform their recommendations, subject to calendar and budget constraints, including in-store customer intercepts, revealed preference models, and a market model, with either an independent advisor and reviewer or use of a Delphi panel. The NTG assumptions for all LEDs in year 2020 and beyond will be assessed by DTE evaluators in 2019. The evaluators' draft recommendations for both (1) 2019 and (2) 2020 and beyond will be discussed with NRDC and Staff before being finalized.

8. Plan Amendment Threshold Requirements. DTE Electric shall seek an amendment of the Plan if the Company intends to exceed the approved Plan spend by more than 5%.

9. Residential Cost Allocation. DTE Electric will remove education program costs from the customer class allocation percentage calculation in its 2020-2021 EWR Plan. The Company will implement a cost tracker for its education program in 2018 and 2019. The education program cost tracker will inform the allocation of education program expenses between residential and commercial & industrial in the Company's 2020-2021 EWR Plan.

10. The Company's 2020-2021 Plan will include discussion detailing the calculation of its residential, commercial & industrial, and low-income administrative and infrastructure costs.

11. The Parties agree that DTE Electric will begin to charge the 2018-2019 EWR base rates proposed in this Plan effective with bills rendered in May 2018. The total EWR charge implemented will consist of the base rate and the 2016 performance incentive component approved

in Case No. U-18332 (Order dated December 20, 2017), as set forth in Attachment F. Actual revenues and costs will be included in the annual reconciliation.

12. This Settlement Agreement is entered into for the sole and express purpose of reaching a compromise among the Parties. All offers of settlement and discussions relating to this Settlement Agreement are considered privileged under MRE 408. If the Commission approves this Settlement Agreement without modification, neither the Parties to this settlement nor the Commission shall make any reference to, or use this Settlement Agreement or the order approving it, as a reason, authority, rationale, or example for taking any action or position or making any subsequent decision in any other case or proceeding; provided however, such references may be made to enforce or implement the terms of the Settlement Agreement and the order approving it.

13. This Settlement Agreement is not severable. Each provision of this Settlement Agreement is dependent upon all other provisions of this Settlement Agreement, including the attachments. Failure to comply with any provision of this Settlement Agreement, including commitments phrased in firm language (such as "shall" or "will") in the attachments, constitutes failure to comply with the entire Settlement Agreement. If the Commission rejects or modifies this Settlement Agreement, this Settlement Agreement shall be deemed to be withdrawn, and shall not constitute any part of the record in this proceeding or be used for any other purpose, and shall not operate to prejudice the pre-negotiation positions of any party.

14. This Settlement Agreement is reasonable and in the public interest, and will reduce the time and expense of the Commission, its Staff, and the Parties.

15. The Parties agree to waive Section 81 of 1969 PA 306 (MCL 24.281), as it applies to the issues in this proceeding, if the Commission approves this Settlement Agreement without modification.

16. This Settlement Agreement may be executed in any number of counterpatis, each considered an original, and all counterparts that are executed shall have the same effect as if they were the same instrument.

IN WITNESS WHEREOF, the Parties have caused this Settlement Agreement to be duly executed by their respective du ly authorized officers as of the date first written below.

DTE ELECTRIC COMPANY

Andrea Hayden
Digitally signed by Andrea Hayden
DN:cn=Andrea Hayden,o=GeneralCounsel-Regulalory,ou;:General Counsel - Regulatory,
emall=andrea.hayden@dteenergy,com, c=US
Dale:1018 03.20 14,47-45--04'00'

By: ______________________ Dated: ____________________, 2018

Andrea E. Hayden (P71976)
DTE Electric Company
One Energy Plaza, Detroit, MI 48226
(313) 235-3813

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

Spencer Sattler
Dlgll•ll)l olgned b)' Spence< S•ttle.-
ON:<r>=Spencer5attler,o-Mk:hi9anD•J>llnmonl ofAttomreyGonor• ?u=Publi<Se"llce DMolon,
•m•ll,,.•lllern!!>mlc19on,ii<JY, c=US
Dale:2\11B.ol.1609:04:2l-04'00'

By: ______________________ Dated: ____________________, 2018

Spencer Sattler (P70524)
Assistant Attorney General
7109 West Saginaw Hwy, 3cd Fl
Lansing, MI 48917
(517) 241-6680

NATURAL RESOURCES DEFENSE COUNCIL

Digitally signed by Christopher M. Bzdok
DN: cn=Christopher M. Bzdok, o=Olson, Bzdok & Howard, P.C., ou,
email=chris@envlaw.com, c=US
Date: 2018.03.15 18:18:10 -04'00'

By: ______________________ Dated: March 15, 2018

Christopher M. Bzdok (P53094)
Olson, Bzdok & Howard, P.C.
420 E. Front Street
Traverse City, MI 49686

NATIONAL HOUSING TRUST

Digitally signed by Lydia Barbash-Riley
Date: 2018.03.15 16:19:38 -04'00'

By: ____________________________ Dated: March 15, 2018

Lydia Barbash-Riley (P81075)
Olson, Bzdok & Howard, P.C.
420 E. Front Street
Traverse City, MI 49686

RESIDENTIAL CUSTOMER GROUP

By: Don L. Keskey Dated: March 16, 2018

Don L. Keskey
University Office Place
333 Albert Avenue, Suite 425
East Lansing, MI 48823

# Attachment A – Low Income Program Changes

The following information describes the increased ramping efforts of DTE Electric Company ("DTE Electric") and DTE Gas Company ("DTE Gas") (collectively the "Companies") in the Energy Efficiency Assistance (EEA) program to target low income customers in arrears. Low income customers are defined as those customers with income at or below 200% of the federal poverty limit. Customers may be eligible for this program regardless of home ownership or renting status.

The Companies will increase Electric and Gas EEA program spend by a total of $5,000,000 for the EWR 2018-2019 plan to target low income customers in arrears

- 2018: $1,000,000 at a minimum to be spent on energy efficiency measures for low income customers in arrears
- 2019: Spend the balance of the of the $5,000,000 increase made to the EWR 2018-2019 plan to be focused at low income customers in arrears

The methodology that will be used by the Companies to target low income customers in arrears will be as follows:

- Leverage the billing systems of the Companies to identify customers in arrears. Low income status will also be identified if data is available in the billing system.
- The customer list will be sorted and prioritized by customers with the highest amount in arrears; meaning that customers with the highest arrears will be targeted first
- Customers with the highest energy intensity will be the next step in prioritization
    - Energy intensity is defined by the ratio of annual energy consumption used per square foot in the home
        - Energy usage data will be provided via the Company billing system
        - Household square footage data will be obtained through Company owned or procured records
- This customer list will then be segmented geographically based on regions that are served by community action agencies (CAAs), non-profit organizations or appropriate government agencies that facilitate energy efficiency assistance.
- The segmented lists will be provided to the appropriately agencies.
- The Company will work with the agencies to extend the EEA program to this targeted audience.
- Customer participation will be identified through records provided to Company by the agencies.

For low income multifamily customers, the Companies will:

1. Identify customers that are in arrears who are residing in buildings participating in the low-income multifamily program. The Companies will conduct a study that begins at the end of 2019 to understand the impacts of this program on bill payment by multifamily low income customers in arrears. Items that the Companies may track in the study include:

- reduction of write-offs
- reduction of money that is in arrears
- Timeliness of payments
- Number of payments
- Regularity of payment
- Unsolicited nature of payment (reduction of shut-off/past due)
- Complete Bill Payment:
- Regular Bill Payment

2. Using billing and other data, and looking at the entire population of multifamily buildings in its territories, the Companies will document and report out on whether there appear to be clusters of customers in arrears within specific multifamily buildings. This may identify areas for future increases in targeting and spending.

The Companies expect that the majority of the $5,000,000 increase will be spent on measures provided to the low-income customers in arrears. It is anticipated that the Company will leverage the existing EEA program to deliver this increase. The EEA program currently does and will continue to contract the implementation of this program. The implementation contractor will continue to work with established channels (community action agencies and/or non-profit organizations and/or appropriate government agencies) to drive the increased volumes. The Companies anticipate that about 10%-15% of the total increase will be used for the administration costs.

## Attachment B – Multifamily Low Income Commercialized Program

DTE Electric Company ("DTE Electric") and DTE Gas Company ("DTE Gas") (collectively the "Companies") will conduct a Low Income Multifamily pilot to determine an appropriate level of incentives for this program. National Housing Trust ("NHT") has reviewed and provided input to the design of the pilot. The incentive levels that are learned from the pilot will be used to set the incentive levels of the commercialized Low Income Multifamily program in 2019. Additionally, the other learnings (such as assessment, assessment reports, DI measures and the implementation staff necessary to deliver the program enhancements) from the pilot will be incorporated into the commercialized program as soon as possible in 2018.

In addition to incorporation of the learnings from the pilot, the following are changes that will be incorporated into the Multifamily Low Income 2018 program:

<u>Increase in Electric and Gas Multifamily Low Income Spend and removal of caps</u>

- 2018: $250,000 for a total of $ 2,195,000 Electric and Gas funding (not including pilot spending)
- 2019: $3,000,000 for a total of $4,955,000 Electric and Gas funding (not including pilot spending)
-

<u>Savings and spend accounting for the Multifamily Low Income program</u>

- All funding for the Multifamily Low Income program is from the Multifamily Low Income program budget, the spending and savings for which will be reported as a separate line item in the Companies' EWR Plan reconciliation filing documents.
- All spend and savings for in-unit direct install, common area direct install, in-unit non-direct install, and common area non-direct install for eligible multifamily low income projects will be accounted to the multifamily low income program
- All Multifamily Low Income projects will be provided an expanded list of in-unit direct install measures and Common Area direct install measures (see below).
- All Multifamily Low Income projects being provided Common Area non-direct install with higher incentive levels must be managed through the Multifamily Low Income program's concierge efforts.
- For the Multifamily Low Income program's concierge managed projects there are no project / building spend caps.

<u>Assessment Report</u>

The Companies will review best practices of landlord portal capabilities, specifically related to the aggregation of energy usage for entire multifamily buildings and, in conjunction with stakeholder input, will use this information to improve access to data from non-landlord-managed meters for both landlords and the Multifamily Low Income program administrator. The current working aspects of the energy assessment are as follows:

- Interviews with site operating personnel, review of 12 months of Electric and Gas utility bills, site walk through to identify Energy Efficiency Measure(s) and overall unit/building conditions (duration of walk through varies by size of the building)

- Collect field data, age, efficiency and operating conditions for the following possible energy efficiency areas, where applicable:
    - Heating, Ventilation & Air Conditioning (HVAC)
    - Plumbing Equipment & Fixtures
    - Insulation Levels
    - Windows & Doors
    - Lighting & Electrical
    - Major Appliances and Plug Load
    - Building Envelope
    - Elevators

DTE Level I Energy Assessment report components to include but not limited to:

- List of Energy Efficiency Measure(s), with estimated energy savings, estimated cost savings, and estimated cost for equipment and installation; including low cost and direct install measures
- % Energy Cost Savings
- % Energy Savings by Energy Efficiency Measure(s)
- Simple Payback by Energy Efficiency Measure(s)
- Incentive Package Options
- Summary of utility data with building energy profile
- Energy Star Portfolio Benchmarking of EUI to EUIs of similar sites
- Identification of comprehensive capital investments (DTE Level II Energy Assessment required) - For such investments, the Level I Energy Assessment report will provide a general range for energy savings, cost savings, simple payback, and capital/installation costs to be used for preliminary decision making. A more accurate forecast of costs may be developed pending further analysis.

<u>Measures</u>

Measure offerings listed below may be changed upon mutual agreement between the Companies and NHT.

- <u>In-unit direct install measures</u>
    - Energy efficient showerheads
    - Bathroom faucet aerators
    - Kitchen faucet aerators
    - LED bulbs (various types)
    - LED Nightlights
    - Hot water pipe wrap
    - Shower start valves

- Occupancy sensors
- Advanced Power Strip (where applicable)
- Lower domestic hot water temperature (per code) – no savings
- Furnace tune-ups
- Refrigerators replacement*
- In unit window air conditioners*

  *Covered at 100% cost to tenant bearing utility bill, offered as part of incentive tiers (or at regular incentive levels before the tiers are rolled out) for all other participants

- Common Area direct install measures
  - LED Lighting
  - Hot water pipe wrap
  - Bath faucet aerators
  - Occupancy sensors
  - Thermostats
  - Hard Wired LED fixtures
  - LED screw-lamps
  - LED exit signs
  - LED parking lot & safety lighting
  - Energy efficient focused system controls - sensors, timers, dimmers
  - Furnace tune-ups
  - Heating and DHW boiler tune-ups

- Common Area and in-unit non-direct install
  - The enhanced incentive levels proposed for 2019 will be determined by the Companies' Multifamily Low Income program pilot.
  - Incentives for Common Area non-direct install measures are available in the Multifamily Low Income program for either centrally or individually metered building configurations.
  - Continue to offer the entire suite of residential and C&I measures as prescriptive or custom measure
  - The following measures will also be included:
    - Prescriptive measures duct sealing, air sealing and roof insulation will be made available as incentivized items. These measures will be added to the program's literature and be available in 2018.
    - Custom measure crawl space insulation will be made available as an incentivized item. This measure will be added to the program's literature and be available in 2018.

Eligibility guidelines for low-income multifamily program and/or pilot

Eligibility will be established based on one or more of the following factors:

1. Participation in an affordable housing program. Automatic qualification for any property that can provide evidence of participation in a federal, state, or local affordable housing program, for example: LIHTC, HUD, USDA, MSHDA, local tax abatement for low-income properties, etc.
2. Location in a low-income Census Tract. Location in a Census Tract identified by the Company as low-income. As a starting point, the Company will use HUD's annually published "Qualified Census Tracts," but the target Census Tracts may be adjusted based on Company experience and/or consultation with stakeholders.
3. Rent roll documentation. Submission of rent rolls documenting that the average rents charged by a particular property are affordable to households meeting HUD's definition of low-income, which is 80% of Area Median Income. The starting point for this table will be rents at or below 80% of "Fair Market Rent" as published annually by HUD. The Company may adjust this table of maximum rent guidelines based on Company experience and/or consultation with stakeholders.
4. *Tenant income information. Submission of tenant income information showing that at least 50% of units are rented to households meeting one of the following criteria:
    a. At or below 200% of the Federal Poverty Level
    b. At or below 80% of Area Median Income
5. Participation in the Weatherization Assistance Program. Submission of documentation showing that the property is on the waiting list for, currently participating in, or has in the last five years participated in, the Weatherization Assistance Program.

*This option will only be used if the other approaches are not applicable/possible.

Low Income Targeting Procedures

- Identify and market to properties that have been identified by federal and state agencies (e.g. LIHTC, Section 8, MSHDA 236, HUD Housing)
- Identify and market to properties that fall within the Qualified Census Tracts

Collaboration

DTE Electric and DTE Gas commit to initiate conversations with Consumers Energy explaining the DTE Multifamily Low Income Pilot and eventual transition into the commercialized program in 2019. In the conversation(s) DTE Electric and DTE Gas will make a good faith effort to:

- Propose leveraging a common vendor (or sub-vendor) to execute the program
- Propose the advancement of collaboration/coordination of:
    - Shared energy assessments
    - Standardizing between utilities in-unit direct install measures
    - Standardizing between utilities Common Area direct install measures
- find Determine whether DTE Electric's assessment and concierge services can be supported by either Consumers Energy or the Companies, for a single customer experience that services both utilities.
- Evaluate the possibility of providing leads and the management of them by either utility's concierge services.

Incentive Reservation

DTE Electric and DTE Gas will each adopt a reservation system for the low income multifamily program that is similar to the C&I program's reservation system. In this process, the low income multifamily property owner/manager would commit to the project and via the concierge, an application for incentives would be completed. The property owner/manager would then receive a letter of incentive reservation that is good for 90 days. The concierge will keep close tabs on the status of the project and will extend the reservation as necessary. The program implementer, via marketing / outreach efforts and the services of concierge, is responsible for the overall spending and savings of the program and therefore must manage the program accordingly. Thus if the low income multifamily project that has reserved incentives is not going to be completed by the end of the calendar year, the incentives must be released to another low income multifamily project that will be able to be completed. The projects that carry into the following year may have incentives reserved for them again ahead of other new projects.

Program Update

DTE Energy would like to continue the conversation with NHT to consider their ideas and some best practices that maybe incorporate into the commercialized program. DTE will take part in quarterly update meetings with the National Housing Trust, Staff, and Multifamily Program consultant from NRDC. These meetings will provide updates to the pilot and features being incorporated into the commercial program from the pilot.

The first quarterly program update will occur no later than 4/25 of the current program year, and include 1/1 through 3/31 of the current program year. Subsequent updates will occur on:

- 7/25 for data from 4/1 through 6/30
- 10/25 for data from 7/1-9/30
- 2/15 following the program year end for data from 10/1-12/31

Quarterly meetings may be rescheduled to mutually agreeable dates based on data and participant availability.
DTE Electric and DTE Gas will track data for participants in the following categories: Project, Measure, Investment, and Savings. DTE Electric and DTE Gas will share the data outlined below with NHT at the agreed upon quarterly updates to provide input and foster further Pilot and program discussions.

The reporting data listed below may be changed upon mutual agreement between the Companies and NHT. Data reported will include but is not limited to the following:
Project Level Data (a "project" = a "property" for reporting purposes)

- Projects, buildings, and units served – for a single property all savings and measures will be reported together
    - # projects, buildings and units served
- % of projects that received benchmarking services
- % of projects that received a Level I energy assessment

- % of projects that received a Level II energy assessment
- % of projects that installed 2 or more prescriptive or custom measures
- % of projects that proceed with 50% or more of the recommended measures from their energy assessments
- Subsidized and Unsubsidized properties participating

Measure Level Data

- # of Projects reported above that received incentives in the following categories:
    - HVAC
    - Insulation
    - Lighting
    - Domestic Hot Water
    - Custom
- Total # of installations, in the Projects reported above, for each DI measure
- % of projects that participated only in DI
- % of projects that received only prescriptive or custom incentives
- % of projects that received both direct install and prescriptive and/or custom incentives
- % of projects that received an energy assessment and opted not to proceed

Investment Data

- Paid incentives
    - Total electric incentives paid to projects
    - Total gas incentives paid to projects
- Total non-incentive budget (by fuel) for low-income multifamily program
- Total incentive budget (by fuel) for low-income multifamily program
- Incentives as a portion of total actual or estimated project cost (including both materials and labor)
    - Average % of project total cost covered by incentives (exclusive of direct install)

Savings Data

- MWh savings achieved
    - Total savings achieved in paid projects
- Mcf savings achieved
    - Total savings achieved in paid projects
- Average % savings of total energy use per project
    - Average % savings of electricity per project
    - Average % savings of gas per project

Outreach Data

- # of phone program inquiries by qualified owners/managers
- # of electronic program inquires received
- # of site visits completed by outreach staff

# Attachment C – Multifamily Low Income Pilot

## Objective:

The Companies will conduct a pilot described in this attachment. The objective of the pilot is to develop, test, implement, and refine a process to complete whole building energy assessments and energy efficiency services for low-income multifamily buildings. The Pilot work will begin with development of a process to identify eligible participants (dual fuel, low income multifamily buildings) and continue through the completion of a DTE Level I Energy Assessment to ASHRAE standards (DTE Level I Energy Assessment), testing of tiered incentive levels, assessing need for a DTE Level II Energy Assessment, facilitating trade ally bidding, assisting in applying for financing opportunities (if needed), monitoring QA/QC of project work completion, issuing incentives, and concluding with the improvement and refinement of the process from start to finish, with a goal to integrate learnings into the commercialized Multifamily program, as they are identified, during the 2018-19 plan cycle. All participants will be guided through entire pilot process via a concierge service to ensure a "one stop shop" experience.

## Target Market:

Low income multifamily buildings with three or more units and taking service from DTE Electric Company ("DTE Electric") or DTE Gas Company ("DTE Gas") (collectively the "Companies") are eligible for this Pilot. The target market is dual fuel low income multifamily, subsidized buildings, servicing both in-unit tenant paid and whole building master-metered locations.

## Pilot Duration:

The Pilot is scheduled to start in the first quarter of 2018, with an 18-24-month duration once launched.

## Pilot Description:

The pilot is intended to test tiered incentive levels to determine which tiers will drive participants to install deeper energy efficiency measures, which will ultimately lead to a lower burden on low-income individuals. High level phases, which will be executed by external implementation contractors, may include but are not limited to:

**1. Pilot Design & Development Plan Refinement** - Work with implementation contractor to refine the pilot implementation design and marketing/outreach plans. DTE Electric and DTE Gas will take part in quarterly update meetings with the National Housing Trust ("NHT") and Multifamily Program consultant from NRDC.

**2. Participant pooling & feasibility** – Identify at least 30 potential target market participants by working with MSHDA and other multifamily stakeholders, and by conducting an initial screening contact (e.g. telephone screening). For those participants deemed to have a high likelihood of participating, we will complete a Preliminary Energy Assessment. A Preliminary Energy Assessment is defined as an assessment to analyze energy use, energy cost and develop the Energy Cost Index (ECI) of buildings and the Energy Utilization Index (EUI). The EUI will be compared to similar buildings' EUIs to assess the potential for improved energy performance and benefit from program participation. This assessment will provide background for the DTE Level I and Level II Energy Assessments. Once a narrowed participant pool is identified, feasibility screening will be used to identify participants which should move forward to a DTE Level I Energy Assessment. The feasibility screening process may include but is not limited to points shown below:

- High level report on potential energy savings, detailed by measure and/or building system and direct install opportunities
- Initial interview with potential participants to gauge interest in capital improvements and understand major areas of energy efficiency concerns
- ECI & EUI Analysis

Pilot will review best practices for gathering tenant meter information and identify possible changes to the Companies' landlord portal.

**3. DTE Level I Energy Assessments-** Conduct an estimate of 20 DTE Level I Energy Assessments, which will contain each of the following when applicable, but are not limited to the list below. Since multifamily buildings are unique, additional modifications may be required.

- Interviews with site operating personnel, review of 12 months of Electric and Gas utility bills, site walk through to identify Energy Efficiency Measure(s) and overall unit/building conditions (duration of walk through varies by size of the building)
- Collect field data, age, efficiency and operating conditions for the following possible energy efficiency areas, where applicable:
    - Heating, Ventilation & Air Conditioning (HVAC)
    - Plumbing Equipment & Fixtures
    - Insulation Levels
    - Windows & Doors
    - Lighting & Electrical
    - Major Appliances and Plug Load
    - Building Envelope
    - Elevators

DTE Level I Energy Assessment report components to include but not be limited to:

- List of Energy Efficiency Measure(s), with estimates for energy savings, estimated cost savings, and estimated cost for equipment costs and installation; including low cost and direct install measures

- % Energy Cost Savings
- % Energy Savings by Energy Efficiency Measure(s)
- Simple Payback by Energy Efficiency Measure(s)
- Incentive Package Options
- Summary of utility data with building energy profile
- Energy Star Portfolio Benchmarking of EUI to EUIs of similar sites
- Identification of comprehensive capital investments (DTE Level II Energy Assessment required) - For such investments, the Level I Energy Assessment report will provide a general range for energy savings, cost savings, simple payback, and capital/installation costs to be used for preliminary decision making. A more accurate forecast of costs may be developed pending further analysis.

**4. Incentive Tiers -** Incentives will be designed with escalating tiers to encourage deeper energy savings. Incentive tiers will be applied to total project costs inclusive of equipment and labor, and total project energy savings inclusive of direct install savings:

- 25% incentive (against total project cost) if measures installed generate at least 10% annual energy reduction
- 35% incentive (against total project cost) if measures installed generate at least 15% annual energy reduction
- 40% incentive (against total project cost) if measures installed generate at least 20% annual energy reduction
- 50% incentive (against total project cost) for in-unit measures not listed as direct install measures for tenant paid utilities (see direct install measures below), regardless of savings generated
- For measures that do not qualify with at least 10% annual energy reduction, an incentive of 20% will be offered

Incentive tiers to be reevaluated based on participation. Pilot participants reengaging in a new project after completing a DTE Energy Assessment will be considered for automatic advancement to proceeding incentive tier. *

*The Companies will establish a reasonable participation and project timing threshold for automatic advancement.

Participants of DTE Level I Energy Assessment to be offered direct install measures, detailed in the eligible measures section below, regardless of acceptance of incentive tiers. Participants do not need to receive direct install measures to receive DTE Level I Energy Assessment.

**5. DTE Level II Energy Assessment -** Conduct an estimate of 8 DTE Level II Energy Assessments. Criteria to necessitate these assessments are as follows:

- Property is approaching financing event and owner plans to undertake capital improvements

- Equipment failure or deterioration conditions that necessitate replacement (e.g. HVAC system & windows)

Key elements of DTE Level II Energy Assessment final report to include but not be limited to:
- Bid Package with detailed project cost
- Energy Modeling
- Deeper analysis of utility bills, to provide participants with comprehensive understanding of financial benefits of implementing identified Energy Efficiency Measure(s).

**6. Retrofitting & Implementation –** Target to complete retrofits projects to at least 2 properties. For each Project, participant will be assisted in assembling a Bid Specification package that details work sought for completion of EE measures. All contractors will be state licensed and mutually approved by Company and participant to ensure competitive bid with reputable contractor. At least 3 competitive bids will be considered. Company will establish a competitive bid process to ensure transparency.

**7. Refinements & Improvements for possible commercialization -** Complete Quality Assessment/Quality Control (QA/QC) and "as built" documentation required for post-completion cost effectiveness analysis

- Work with Implementation Contractor to make changes which will increase participation and Project completion rates. Aim to achieve a higher rate of energy savings for low income participants in a manner which allows for as many low-income buildings as possible to complete comprehensive retrofits for the allocated budget.
- Maintain a work file of electronic and scanned/written documents for each Project, and provide Company with a complete copy at the time of each Project completion
- Contractor will complete a Final Report after the Pilot summarizing the work completed, lessons learned, recommendations for improvements of the Pilot, and program commercialization potential. However, for lessons learned identified earlier in the Pilot, these may be incorporated into the commercialized program along the way without waiting for the Final Report findings.

## Measures:

All measures (in unit & common) currently offered in the commercialized Multifamily program to be offered to Pilot participants.

- In-unit direct install measures
    - Energy efficient showerheads
    - Bathroom faucet aerators
    - Kitchen faucet aerators
    - LED bulbs (various types)
    - LED Nightlights
    - Hot water pipe wrap
    - Shower start valves

- Occupancy sensors
- Advanced Power Strip (where applicable)
- Lower domestic hot water temperature (per code) – no savings
- Furnace tune-ups
- Refrigerators replacement*
- In unit window air conditioners*

  *Covered at 100% cost to tenant bearing utility bill, offered as part of incentive tiers for all other participants.

- Common Area direct install measures
  - LED Lighting
  - Hot water pipe wrap
  - Bath faucet aerators
  - Occupancy sensors
  - Thermostats
  - Hard Wired LED fixtures
  - LED screw-lamps
  - LED exit signs
  - LED parking lot & safety lighting
  - Energy efficient focused system controls - sensors, timers, dimmers
  - Furnace tune-ups
  - Heating and DHW boiler tune-ups

- Incentives for non-direct install measures will be available.
  - Entire suite of current residential and C&I measures will be offered as prescriptive or custom measures.
  - The following potential measures will also be included and will be treated in the following way
    - Prescriptive measures for duct sealing, air sealing and roof insulation will be made available as incentivized items.
    - Custom measure crawl space insulation will be made available as an incentivized item.

## Implementation Strategy:

The Companies will provide program management and oversight, vendor referrals, tracking and reporting oversight, and regulatory review. The Companies will utilize an Implementation Contractor(s) (IC) to provide implementation services, including outreach, marketing, building assessments and direct installations, and quality control for measures installed by other contractors. IC to be responsible to obtain adequate staffing required to conduct DTE Level I and II Energy Assessments, bid specifications and retrofit completion. All contractors utilized to be licensed and insured in state of Michigan. IC to assign concierge to assist with: the conducting and testing of effectiveness of the DTE Level I and II Energy Assessments; facilitating financing; and assistance with identifying and securing licensed contractor(s) to perform energy efficiency upgrades; testing of incentive levels; and complete quality assessment and control.

## EM&V Requirements:

An independent EM&V contractor will perform the evaluation of the program, which will have an energy impact evaluation and a process evaluation. As part of the impact evaluation, the EM&V contractor will determine audited deemed savings based on a review of program tracking data to ensure that appropriate MEMD values are applied and that supporting documentation is accurately recorded. The impact evaluation will also include primary data collection to assess measure installation and persistence, as well as free ridership and spillover. These efforts will support the development of an Installation Rate Adjustment Factor (IRAF) and Net to-Gross ratio (NTG). The process evaluation is intended to provide program managers with timely recommendations on program operations, and effectiveness, as well as methods to increase program induced savings and participant satisfaction. The process evaluation will also assess the subcontractors' performance. Key tasks include in-depth interviews with program staff, property managers and participating customers to assess satisfaction with the program and participation processes, and barriers to installing non-direct install measures in tenant units and in common areas.

## Estimated Participation:

30 potential participants
20 DTE Level I Energy Assessments
8 DTE Level II Energy Assessments
Retrofit projects to at least 2 properties (will not be capped to 2 properties)

## Budget:

$1,000,000 over 18-24-month duration of pilot inclusive of Implementation & Incentive.

## Data Tracking:

DTE Electric and DTE Gas will track data for participants in the following categories: Project, Measure, Investment, and Savings. The Companies may share data collected as deemed appropriate with NHT at the agreed upon quarterly status meetings to provide input and foster further Pilot discussions.
Data tracked may include but not limited to the following:
<u>Project Level Data (a "project" = a "property" for reporting purposes)</u>

- Projects, buildings, and units served – for a single property all savings and measures will be reported together
  - # projects, buildings and units served
- % of projects that received benchmarking services
- % of projects that received a Level I energy assessment
- % of projects that received a Level II energy assessment
- % of projects that installed 2 or more prescriptive or custom measures

- % of projects that proceed with 50% or more of the recommended measures from their energy assessments
- Subsidized and Unsubsidized properties participating

Measure Level Data

- # of Projects reported above that received incentives in the following categories:
    - HVAC
    - Insulation
    - Lighting
    - Domestic Hot Water
    - Custom
- Total # of installations, in the Projects reported above, for each DI measure
- % of projects that participated only in DI
- % of projects that received only prescriptive or custom incentives
- % of projects that received both direct install and prescriptive and/or custom incentives
- % of projects that received an energy assessment and opted not to proceed

Investment Data

- Paid incentives
    - Total electric incentives paid to projects
    - Total gas incentives paid to projects
- Total non-incentive budget (by fuel) for low-income multifamily program
- Total incentive budget (by fuel) for low-income multifamily program
- Incentives as a portion of total actual or estimated project cost (including both materials and labor)
    - Average % of project total cost covered by incentives (exclusive of direct install)

Savings Data

- MWh savings achieved
    - Total savings achieved in paid projects
- Mcf savings achieved
    - Total savings achieved in paid projects
- Average % savings of total energy use per project
    - Average % savings of electricity per project
    - Average % savings of gas per project

Outreach Data

- # of phone program inquiries by qualified owners/managers
- # of electronic program inquires received
- # of site visits completed by outreach staff

## Quarterly Meetings:

Reporting timeline – The first quarterly update will occur no later than 4/25 of the current program year, and include 1/1 through 3/31 of the current program year. Subsequent updates will occur on:

- 7/25 for data from 4/1 through 6/30
- 10/25 for data from 7/1-9/30
- 2/15 following the program year end for data from 10/1-12/31

Quarterly updates may be rescheduled to mutually agreeable dates based on data and participant availability. Pilot design/scope may be modified based on mutually agreeable decisions between the Companies and NHT.

# Attachment D – Electric Performance Incentive Mechanism

| | Legislative First Year Savings Tiers | | Lifetime Savings (MWH) | | Low-Income Spend ($1,000) | | Low-Income Multi-Family Assessments* | |
|---|---|---|---|---|---|---|---|---|
| | | | Minimum (100%) | | Minimum (100%) | | Minimum (100%) | |
| | | | YR 2018 | 5,181,264 | YR 2018 | $7,889 | YR 2018 | 20% |
| | | | YR 2019 | 5,152,884 | YR 2019 | $7,890 | YR 2019 | 30% |
| | | | Weight | 80% | Weight | 15% | Weight | 10% |
| | % Savings | % Incentive | % Savings | % Incentive | % Spend | % Incentive | % Assessments | % Incentive |
| **Tier 1** | **1.00%** | **15.00%** | 100% | 12.00% | 100% | 2.00% | 100% | 1.00% |
| | 1.01% | 15.10% | 101% | 12.08% | 101% | 2.02% | 101% | 1.02% |
| | 1.02% | 15.20% | 102% | 12.16% | 102% | 2.04% | 102% | 1.04% |
| | 1.03% | 15.30% | 103% | 12.24% | 103% | 2.06% | 103% | 1.06% |
| | 1.04% | 15.40% | 104% | 12.32% | 104% | 2.08% | 104% | 1.08% |
| | 1.05% | 15.50% | 105% | 12.40% | 105% | 2.10% | 105% | 1.10% |
| | 1.06% | 15.60% | 106% | 12.48% | 106% | 2.12% | 106% | 1.12% |
| | 1.07% | 15.70% | 107% | 12.56% | 107% | 2.14% | 107% | 1.14% |
| | 1.08% | 15.80% | 108% | 12.64% | 108% | 2.16% | 108% | 1.16% |
| | 1.09% | 15.90% | 109% | 12.72% | 109% | 2.18% | 109% | 1.18% |
| | 1.10% | 16.00% | 110% | 12.80% | 110% | 2.20% | 110% | 1.20% |
| | 1.11% | 16.10% | 111% | 12.88% | 111% | 2.22% | 111% | 1.22% |
| | 1.12% | 16.20% | 112% | 12.96% | 112% | 2.24% | 112% | 1.24% |
| | 1.13% | 16.30% | 113% | 13.04% | 113% | 2.26% | 113% | 1.26% |
| | 1.14% | 16.40% | 114% | 13.12% | 114% | 2.28% | 114% | 1.28% |
| | 1.15% | 16.50% | 115% | 13.20% | 115% | 2.30% | 115% | 1.30% |
| | 1.16% | 16.60% | 116% | 13.28% | 116% | 2.32% | 116% | 1.32% |
| | 1.17% | 16.70% | 117% | 13.36% | 117% | 2.34% | 117% | 1.34% |
| | 1.18% | 16.80% | 118% | 13.44% | 118% | 2.36% | 118% | 1.36% |
| | 1.19% | 16.90% | 119% | 13.52% | 119% | 2.38% | 119% | 1.38% |
| | 1.20% | 17.00% | 120% | 13.60% | 120% | 2.40% | 120% | 1.40% |
| | 1.21% | 17.10% | 121% | 13.68% | 121% | 2.42% | 121% | 1.42% |
| | 1.22% | 17.20% | 122% | 13.76% | 122% | 2.44% | 122% | 1.44% |
| | 1.23% | 17.30% | 123% | 13.84% | 123% | 2.46% | 123% | 1.46% |
| | 1.24% | 17.40% | 124% | 13.92% | 124% | 2.48% | 124% | 1.48% |
| Tier 2 | **1.25%** | **17.50%** | 125% | 14.00% | 125% | 2.50% | 125% | 1.50% |
| | 1.26% | 17.60% | 126% | 14.08% | 126% | 2.52% | 126% | 1.52% |
| | 1.27% | 17.70% | 127% | 14.16% | 127% | 2.54% | 127% | 1.54% |
| | 1.28% | 17.80% | 128% | 14.24% | 128% | 2.56% | 128% | 1.56% |
| | 1.29% | 17.90% | 129% | 14.32% | 129% | 2.58% | 129% | 1.58% |
| | 1.30% | 18.00% | 130% | 14.40% | 130% | 2.60% | 130% | 1.60% |
| | 1.31% | 18.10% | 131% | 14.48% | 131% | 2.62% | 131% | 1.62% |
| | 1.32% | 18.20% | 132% | 14.56% | 132% | 2.64% | 132% | 1.64% |
| | 1.33% | 18.30% | 133% | 14.64% | 133% | 2.66% | 133% | 1.66% |
| | 1.34% | 18.40% | 134% | 14.72% | 134% | 2.68% | 134% | 1.68% |
| | 1.35% | 18.50% | 135% | 14.80% | 135% | 2.70% | 135% | 1.70% |
| | 1.36% | 18.60% | 136% | 14.88% | 136% | 2.72% | 136% | 1.72% |
| | 1.37% | 18.70% | 137% | 14.96% | 137% | 2.74% | 137% | 1.74% |
| | 1.38% | 18.80% | 138% | 15.04% | 138% | 2.76% | 138% | 1.76% |
| | 1.39% | 18.90% | 139% | 15.12% | 139% | 2.78% | 139% | 1.78% |
| | 1.40% | 19.00% | 140% | 15.20% | 140% | 2.80% | 140% | 1.80% |
| | 1.41% | 19.10% | 141% | 15.28% | 141% | 2.82% | 141% | 1.82% |
| | 1.42% | 19.20% | 142% | 15.36% | 142% | 2.84% | 142% | 1.84% |
| | 1.43% | 19.30% | 143% | 15.44% | 143% | 2.86% | 143% | 1.86% |
| | 1.44% | 19.40% | 144% | 15.52% | 144% | 2.88% | 144% | 1.88% |
| | 1.45% | 19.50% | 145% | 15.60% | 145% | 2.90% | 145% | 1.90% |
| | 1.46% | 19.60% | 146% | 15.68% | 146% | 2.92% | 146% | 1.92% |
| | 1.47% | 19.70% | 147% | 15.76% | 147% | 2.94% | 147% | 1.94% |
| | 1.48% | 19.80% | 148% | 15.84% | 148% | 2.96% | 148% | 1.96% |
| | 1.49% | 19.90% | 149% | 15.92% | 149% | 2.98% | 149% | 1.98% |
| Tier 3 | **1.50%** | **20.00%** | 150% | 16.00% | 150% | 3.00% | 150% | 2.00% |

Note: The financial incentive is calculated by adding the percentages earned in each of the 3 metrics. The incentive earned is the lesser of the percentage earned for Legislative First Year Savings Tiers or the combined percentages earned in the 3 other metrics. The total incentive award can not exceed the award based on the Company's Legislative First Year Savings Tiers achieved. *The Low-Income Multi-Family Assessments metric is contingent upon spending the entire Low-Income Multi-family Program and Pilot spend detailed in the settlement agreement.

# Attachment E – Non-Wire Alternatives

**<u>Pilot Program: EWR for Non-Wires Alternative to Distribution Investments</u>**
DTE Electric will conduct a Non-Wires Alternative (NWA) pilot field test. The pilot shall utilize geographically targeted EWR measures as part of the broader NWA program, which may include other components like demand response (DR) and distributed energy resources (DER).. DTE Electric will establish a minimum EWR energy reduction target. The EWR energy savings and any other savings from the NWA pilot, which could defer the need for distribution investments, will be reported to NRDC and MPSC Staff as outlined in paragraph 8 below. However, for the purposes of this pilot, every effort will be made to maximize the amount of EWR savings and subsequent peak savings, even if that means exceeding the identified EWR target. That way the pilot will enable evaluation of the cost-effectiveness of EWR as a non-wires alternative to deferring, reducing the need for, or narrowing the scope of the distribution system capital investment project. The pilot will also enable assessment of the potential to ramp up peak savings in geographically-targeted areas (in order to inform assessment of potential future NWA projects for which greater levels of EWR and other savings may be required to be successful).

DTE Electric, NRDC, and MPSC Staff agree to the following steps and parameters for this pilot project:

1. DTE Electric agrees to work with NRDC, and MPSC Staff on the following:
    a. Provide information regarding the amount, duration, and timing of the EWR energy savings and peak load target chosen for the pilot;
    b. Analysis of the mix of customers in the targeted geographic area, as well as a high-level assessment of the likely potential for achieving targeted savings.

2. DTE Electric, NRDC, and MPSC Staff will work together to agree upon an economic framework and analytical methodology through which the costs and benefits of the EWR measures and programs will be estimated and cost-effectiveness will be measured. EWR funding will only be used for the EWR measures and programs that are a part of this project. This shall include consideration of the benefits of EWR contributing to deferring the distribution system investment, additional avoided energy and capacity costs, and any additional benefits that may be quantified.

3. DTE Electric, NRDC, and MPSC Staff will work together to develop a plan for exceeding the EWR deferral target to the maximum extent possible while still being cost-effective. The plan shall include:

    a. Identifying potential new or existing EWR measures and programs that may be launched in the targeted geographic area, including existing system-wide programs for which marketing efforts and financial incentives may be increased. This may be done alongside other measures and programs funded outside of the EWR pilot funding source.
    b. Develop forecasts of participation rates, savings levels, spending levels and other key elements pertaining to the geographically targeted area.

c. Analysis of how the forecasted participation rates, savings levels, spending levels may impact the target.
d. Development of key metrics that may be tracked and assessed.
e. A process for reviewing progress during the pilot, market response to the pilot, and/or the identification of new opportunities for meeting the target needs more effectively and/or less expensively.

4. DTE Electric, NRDC, and MPSC Staff will seek to exceed the EWR savings reduction target by increasing customer participation in the geo-targeted area via a combination of increased customer outreach, higher incentives, direct installs, etc. as applicable.

5. DTE Electric, NRDC, and MPSC Staff will work together to review an evaluation plan to assess the effectiveness of the pilot and identify key lessons learned regarding what worked well, and how such efforts could be improved in the future. The focus of the evaluation plan will also be to provide retrospective insights after the pilot is completed, and feedback to inform on-going adjustments – as needed.

6. Pilot program launch and deployment – DTE Electric plans to begin implementing the pilot in 2018.

7. Project Report – DTE Electric, NRDC and MPSC Staff will work together to develop a final report after the pilot, which will be included in the appropriate EWR filing with the Michigan Public Service Commission.

8. Process for DTE Electric, NRDC, and MPSC Staff engagement –
   a. The parties will make best efforts to achieve consensus in a timely manner on conclusions regarding each step in the EWR component of the project.
   b. The parties will schedule meetings to complete the initial steps of assessing and selecting the EWR measures and programs, and review the plan for evaluating the pilot.
   c. Once the EWR pilot is launched in the field, check-ins will occur monthly. Parties reserve the right to request additional check-ins through the pilot.
   d. DTE Electric will share data for the substation selected for the EWRNWA pilot strategy development and assess pilot program progress, as approved by DTE Electric following the DTE Energy Third Party Data Sharing Request Process, the MPSC Privacy Tariff and NRDC's acceptance of the DTE Energy Terms and Conditions for the Protection of Company Confidential Information. Approved data sharing will commence provided DTE Electric policy requirements regarding data privacy, background checks, non-disclosure, and security can be met and the appropriate non-disclosure and confidentiality agreements are executed by all participants. Once the pilot has launched, DTE Electric will share any Company approved metrics, evaluation memos or reports as they become available.