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ATTORNEYS AT LAW

DAVID A. BALL

Please Reply To Bridgeport
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August 22, 2017

Via Electronic Filing and Overnight Mail

Attorney Melanie Bachman,
Acting Executive Director
Connecticut Siting Council
Ten Franklin Square
New Britain, CT 06051

Re: ***Docket No. 461A - Eversource Energy application for a Certificate of Environmental Compatibility and Public Need for the construction, maintenance, and operation of a 115-kilovolt (kV) bulk substation located at 290 Railroad Avenue, Greenwich, Connecticut, and two 115-kV underground transmission circuits extending approximately 2.3 miles between the proposed substation and the existing Cos Cob Substation, Greenwich, Connecticut, and related substation improvements. Town of Greenwich Supplemental Pre-Filed Testimony.***

Dear Attorney Bachman:

I've enclosed one (1) original and fifteen (15) copies of the Town of Greenwich's Supplemental Pre-Filed Testimony.

I certify that a copy has been sent on this date to all participants of record as reflected on the Council's service list.

Please do not hesitate to contact me if you have any questions regarding this filing.

Very truly yours,

David A. Ball

DAB/lcc
Enclosures

cc: Service List

THE CONNECTICUT SITING COUNCIL
DOCKET NO. 461A

EVERSOURCE ENERGY APPLICATION FOR A CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AND PUBLIC NEED FOR THE CONSTRUCTION, MAINTENANCE, AND OPERATION OF A 115-KILOVOLT (KV) BULK SUBSTATION LOCATED AT 290 RAILROAD AVENUE, GREENWICH, CONNECTICUT, AND TWO 115-KV UNDERGROUND TRANSMISSION CIRCUITS EXTENDING APPROXIMATELY 2.3 MILES BETWEEN THE PROPOSED SUBSTATION AND THE EXISTING COS COB SUBSTATION, GREENWICH, CONNECTICUT, AND RELATED SUBSTATION IMPROVEMENTS.

Supplemental Testimony of

Denise Savageau

Mitchell E. Mailman

On behalf of

The Town of Greenwich

AUGUST 22, 2017

Town of Greenwich Energy Efficiency Strategy and Actions

Q. Please describe the Town's efforts to develop a long-term energy efficiency strategy.

A. A copy of the Town's Energy Conservation Plan, adopted by the Town's Conservation Commission, is attached as Attachment A (the "Energy Conservation Plan"). Many of the goals set forth in the Energy Conservation Plan have been achieved. The Town is also currently working with Eversource on a memorandum of understanding aimed at developing and implementing a long-term energy efficiency strategy for the entire Town. The strategy will not be limited to Town buildings but will also include commercial and residential customers. Officials from the Town are scheduled to have a strategy planning meeting with Eversource in September.

The Town is also working with the Connecticut Green Bank to identify opportunities for distributed clean energy projects in Greenwich. The Town's efforts in this regard are consistent with the State's long-term energy plans as laid out in the Connecticut Department of Energy and Environmental Protection's draft Comprehensive Energy Strategy dated July 26, 2017. A copy of the Executive Summary from the State Energy Strategy is attached as Attachment B.

Q. Please describe the role of the Connecticut Green Bank in the Town's energy efficiency planning process.

A. The Town has been working with the Connecticut Green Bank since 2007. The Connecticut Green Bank has developed a series of program for communities and provides technical expertise to the Town on clean energy solutions. The Town is engaged with the Green Bank as follows:

- Clean Energy Community since 2008
- Participated in Solarize CT

- Participated in the Sunshot Grant program aimed at streamlining the process and lowering the cost for solar PV installation and local permitting
- Involved with C-PACE Community providing financing to commercial, industrial and institutional building owners for clean energy projects.
- Most recently, working to identify distributed generation projects that produce clean energy and reduce loads and peak loads on the grid. These projects may be single-building or components of a microgrid that contribute to a more modern grid in Greenwich. Attached as Attachment C is a simplified map of the Town of Greenwich identifying a cluster of Town-owned buildings where the Connecticut Green Bank and the Town are considering pursuing distributed generation opportunities such as a microgrid.

Q. Please describe why the Town believes that Eversource's concerns with the current electrical system can be achieved by the implementation of a targeted clean energy program that includes both energy efficiency and distributed energy projects?

A. The Town believes that to the extent there are issues with the Greenwich electrical system relating to redundancy and reliability, those issues can be addressed by doing an assessment of the load distributions and moving forward with projects that both improve energy efficiency and include distributed energy solutions such as the use of microgrids for peak-related emergencies. A strategy aimed at geographically-targeted distributed energy solutions would improve the ability to avoid outages in the event of failures on the electrical system in the Town. This strategy is consistent with the State's draft Comprehensive Energy Strategy.

In December 2016, Eversource gave a presentation to Town officials entitled "Non Transmission Alternative Analysis," a true and correct copy of which is attached as Attachment D. The Town does not agree with the conclusions reached by this analysis. The research report prepared for Northeast Energy Efficiency Partnerships entitled "Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments" attached as Attachment E describes numerous examples where energy efficiency and distributed energy solutions were implemented as an alternative in order to avoid costly distribution and transmission investments such as that proposed by Eversource in this docket. A summary of other recent projects provided to the Town by a representative of the Vermont Energy Investment Corporation (VEIC) attached as Attachment F further demonstrates the ability to increase redundancy and reliability through the use of projects aimed at increasing energy efficiency and implementing distributed generation solutions.

The ability of distributed energy solutions to improve redundancy and reliability in the Town is also highlighted by the construction of the Parkville Microgrid in Hartford. That microgrid provides up to 800-kW of baseload power 24 hours per day, 7 days per week in the City of Hartford at a projected cost-savings relative to the purchase of electricity from the utility. In the event of an outage, the microgrid can serve an islanded load of 640-kW from essential facilities. Eversource and Connecticut Natural Gas were and are critical partners in the successful design, construction, and operation of the microgrid. Moreover, a significant portion of the project was funded by a grant from the DEEP Microgrid Program, which will begin accepting applications for its fourth round of grant making beginning in September 2017. A description of the Parkville Microgrid is attached as Attachment G.[1]

Q. Please describe the Town's efforts over the last decade to increase energy efficiency among Town residents.

A Many of the Town's efforts to increase energy efficiency have been described elsewhere in this Docket (see, e.g., Town of Greenwich Pre-Filed Testimony dated July 18, 2017 at pages 20-21) and in Docket 461 (see Town of Greenwich Responses to CSC Interrogatories 8-10 dated February 16, 2016).

In addition, a timeline of the Town's energy efficiency efforts since 2007 is described in the "Town of Greenwich Clean Energy and Climate Change Timeline 2007 through 2017," attached as Attachment H.

Additional documents demonstrating the Town's commitment to energy efficiency are attached as Attachment I.

Q. Please describe the Town's efforts since June 2016 to increase energy efficiency among Town residents.

A. The Town's efforts since June 2016 to increase energy efficiency among Town residents include the following:

- The Town has been partnering with Eversource and Energize Connecticut to launch the Home Energy Solutions (HES) program since October 2016. As part of the HES program, the Town has been encouraging Town residents to take advantage of the services provided by Energize Connecticut to increase energy efficiency, including sending a joint letter from the Town and Eversource to Town residents encouraging their participation.

[1] A copy of this presentation is available online at: http://www.2017energyexchange.com/wp-content/tracks/track4/T4S9_Matta.pdf

- Through the first three months of the HES program (October – December 2016), 78 audits of residences were conducted, and as a result, Eversource donated approximately $1950 to the Tree Conservancy in April 2017. Through April 2017, 122 home energy audits had been performed through the HES program.
- On April 22, 2017, the Town hosted its second light bulb swap. 357 households attended the light bulb swap, which is the equivalent of 1,785 LEDs swapped out for incandescent and or compact fluorescent light bulbs. In the first light bulb swap in October 2016, 230 households participated, which is the equivalent of 1,159 LEDs swapped out. A third light bulb swap is being planned for this fall to capitalize on the success of the first two. The light bulb swap makes up just one part of the Home Energy Solutions program, which provides lower-cost solutions to residences for increasing energy efficiency, as described in the press release included in Attachment I and on the web site for Energize Connecticut (www.energizect.com).
- On February 22, 2017, Eversource worked with the Town to conduct an energy audit of Town Hall. Once the results of the audit are provided, the Town is prepared to work with Eversource to take responsive steps. The Town also hopes to conduct future audits in order to identify opportunities for improving energy efficiency in Town buildings.
- The Town is currently gearing up to launch the small business advantage program in the fall of 2017, which is the commercial equivalent of the HES program.

<u>**Labor costs associated with installing XLPE solid dialectric cable are significantly less than for HPFF pipe type cable**</u>

Q. Why does the Town believe the labor costs associated with installing a 115-kV XLPE solid dielectric cable from the Cos Cob Substation to a new substation on Railroad Avenue are significantly less than a High Pressure Fluid Filled (HPFF) pipe type cable for the same route?

A. In the July 25 hearing, Eversource's witness questioned the basis for the Town's position that the use of XLPE cable results in costs savings versus use of HPFF pipe type cable. See July 25 Hearing Tr. at 171. The Town believes the labor costs associated with installing a 115-kV XLPE solid dialectric cable are significantly less than a an HPFF pipe type cable for the same route for the following reasons:

HPFF pipe installation is more expensive.

For an HPFF pipe type cable system, each of the joints of the steel pipe has to be welded. (In Docket 461, there were to be two, 8" steel pipes to house the cable and a third, 8" steel pipe to permit the fluid to be recirculated, if so desired, some time in the future.). Anyone welding would have to be a certified welder. Each welding crew would be comprised of a welder and a welder's helper. For each pipe, there would be on average one joint for every 40 feet of trench. Every weld would have to be X-rayed by a radiology laboratory.

The steel pipe needed for an HPFF pipe type cable system would have to be coated to prevent corrosion. Whereas the pipe arrives on-site coated, the area of the weld would have to protected in the field. Before the pipe could be lowered into the trench, the corrosion protection would have to be tested over its full length. No pipe can come in contact with the bottom of the trench when it is placed. Each pipe must be set on sandbags set on average, every ten feet. Any bend in the pipe to have it conform to the trench routing must be made in the field. Pre-formed bends of the steel pipe are not suitable for use. It is likely that production would not exceed eighty trench feet per day.

For a XPLE solid dielectric cable system, however, PVC ducts would be used. This is a very common product that does not require specialized skills to install. Unlike the steel pipe needed for the HPP pipe type cable system, which cannot be lifted without a crane or similar device, the PVC lengths in an XPLE solid dielectric cable system can be picked up by a single person. There are no special jointing techniques needed to extend the lengths. The pipe in an XPLE solid dielectric cable system requires no protective outer coating. Moreover, manufacturers of the pipe in an XPLE solid dielectric cable system can furnish pre-made bends and "spacers" to ensure the ducts do not contact the bottom of the trench and maintain proper spacing between the various conduits.

The production rate of the PVC ducts in an XPLE solid dielectric cable system would on average double that of the steel pipe in an HPFF pipe type cable system and with a much smaller crew and equipment complement.

Proofing the pipe in an HPFF pipe type cable system is more expensive.

The steel pipe in an HPFF pipe type cable system, because it is designed to carry dielectric fluid under high pressure, must be tested after its installation. Before any testing can be started, the inside of the steel pipe must be cleaned. This involves swabbing the pipe from end to end repeatedly. Once clean, the steel pipe can be tested under positive pressure with nitrogen. The steel pipe is pressurized often from a compressed gas trailer to 500 psi. The gas is left in the steel pipe and is monitored for any leakage. Following the positive pressure test, the steel pipe is tested negatively under vacuum. This also removes any moisture in the steel pipe. Once a prescribed dryness value is reached, the vacuumed steel pipe is observed for leakage. It can take days until a section of steel pipe is fully vacuumed. After passing the vacuum test, the steel pipe is once again filled with nitrogen at a low pressure, to keep it dry until it is filled with cable.

By contracts, once the PVC duct in a XLPE solid dielectric cable system is installed, it is merely cleaned of any loose particles and checking for "roundness" - and this can be done in conjunction with pulling the solid dielectric cable.

Installation of the cable in an HPFF pipe type cable system is more expensive.

In an HPFF pipe type cable system, since all three current-carrying conductors are nestled together in the same pipe, all three must be installed together. HPFF cable is quite heavy and the cable reels quite large. Special trailers are needed to contain all three reels. A crane is needed to load the reels into the trailer. In some locales, moving the three reels in the trailer over the road is prohibited, requiring the reels and the trailer to be hauled to the pulling site independently and, with a crane on site, the trailer is loaded.

Each reel, once it is in the trailer, has its own brake to modulate the speed it can turn during the cable pull. Each brake must have its own attendant.

With three heavy HPFF cables being pulled in unison, the pull tensions would be quite high. Specialty-pulling winches, often fitted with 3/4" or large steel winch cables, are used.

Cable pulling for HPFF cables cannot be done in moist weather.

The speed with which the HPFF cables are pulled in can approach 50 feet per minute. However, setting up the reels and equipment prior to the cable pull is arduous. It is usually a 12 to 16 hour day with at least a ten person crew to install one segment of HPFF cable. After the cable is installed, special "end" caps must be put on each end of the pipe to seal it. Nitrogen is then introduced into the pipe to keep the pipe dry.

For XLPE solid dialectric cables, self-loading trailers handle the reels, even if these reels might weigh 60,000 pounds and be 144" in diameter. This obviates the need for a crane to load the reels. Only one cable is installed in a single pipe. To complete the circuit, three pulls must be made, as opposed to the HPFF cable which mandates a single pull. A six person crew can install two lengths of the solid dielectric cable in a 10 to 12 hour work day. As a result, the manhours expended to pull all three legs of an XLPE circuit is less than that of a single HPFF circuit. The equipment costs are less as well. No nitrogen is needed. The weather has no impact on the installation of XLPE cables.

Splicing and terminating HPFF pipe type cable is more expensive.

Great care must be taken with every aspect of an HPFF installation. The same holds for splicing and terminating the cable. These operations are undertaken around the clock, without stoppage, from start to finish, to protect the cables. These activities are extremely time consuming and labor intensive and involve building temperature and moisture conditioned atmospheres. This involves air conditioners, dehumidifiers and heaters and often generators to power this equipment. For the splices, which can take between six and nine days to complete, specially fitted trailers and parked atop the splice vaults. For the terminations, a portable structure must be erected on top of scaffolding in order to seal off the work area. Splicing technicians for HPFF command large monetary premiums.

A set of splices for XLPE solid dielectric cable, including the link boxes and surge arresters, can be completed in five days without working beyond twelve hours a day. The splicing environment needs to be kept dirt free and dry, but does not require any temperature or humidity conditioning. Joints for XLPE solid dielectric cable have also been made simpler in recent years, increasing the number of capable technicians trained to splice. Once the cables are spliced and terminated, they are ready to be tested and immediately thereafter, they can be energized.

By contrast, once the HPFF cables are spliced and terminated, the entire circuit has to be vacuumed to remove any moisture that might have entered the pipe during the splicing, when the pipe ends are opened to the atmosphere. Depending on the length of the feeder and the time of year, this vacuuming could take upwards of a week on a 24 hour basis.

When the HPFF circuit is dry, the fluid can be introduced. This may involve pumping the fluid from the tanker trucks. The oil is added in stages, with carefully regulated stepped increases in pressure. It would likely take almost a week to complete the fill, when the various "rest" periods between pressurizations are factored in. Only after the HPFF cable has been filled can it be tested.

In sum, there is no question that the labor costs associated with the installation of HPFF pipe type cables are far greater than the labor costs associated with the installation of XLPE solid dialectric cables.

Respectfully submitted,

Town of Greenwich

By: ______________________

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CERTIFICATE OF SERVICE

I hereby certify that on this day a copy of the foregoing was delivered by electronic mail to all parties and intervenors of record, as follows:

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ATTACHMENTS

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Attachments to Supplemental Testimony of Denise Savageau and Mitchell E. Mailman
August 22, 2017

7. Town of Greenwich expression of intent to participate in Municipal Climate Intern Program, 2011

8. Flyer for Town of Greenwich energy efficiency fair, 2011

9. Town of Greenwich Clean Energy Municipal Pledge

10. Frequently asked questions relating to 2013 Town of Greenwich renewal of commitment to Clean Energy Communities Program

11. Flyer for Town of Greenwich Solarize Greenwich Workshop, 2013

12. Town of Greenwich Press Release relating to results of Solarize Greenwich program, 2014

13. Agenda for First Selectman's C-PACE Reception and Panel Presentation, September 19, 2013

14. Town of Greenwich receipt of Clean Energy Communities program rewards, August 3, 2015

15. Flyer for Town of Greenwich Light Bulb Swap on October 25, 2016

16. Letter from First Selectman to residents relating to Town of Greenwich Home Energy Solutions program, October 12, 2016

17. Press Release relating to Town of Greenwich Light Bulb Swap, November 23, 2016

18. Flyer for Town of Greenwich Light Bulb Swap on April 22, 2017

ATTACHMENT A

Greenwich Energy Conservation Plan:
September 2016 – adopted by Conservation Commission

I. Overall Energy Program for Community (Conservation Energy Committee)

1. **Modern Grid – determine how grid should look in future**
   a. Net Zero – is it possible
   b. Community Grid – explore options – Town has continued to explore options for a modern grid and has now re-engaged with CT Green Bank – Town does not agree with Eversource that this option has been fully explored

2. **Determine benchmarks:**
   a. Energy Efficiency
   b. Alternative Energy

II. Energy Efficiency

1. **Residential** (Conservation Energy Committee):

   a. Single Family Homes
   i. Home Energy Solutions – will continue through at least Dec 2017
   (a) Set benchmark for campaign
   (b) Outreach Campaign Kick off – October 2016 - done
   (c) Name of non-profit organization to which $25/HES assessment will be donated to – CC to recommend at Sept 1 meeting - done
   (d) Confirm HES vendor partners participating in the campaign: done
   (i) New England Total Energy
   (ii) New England Smart Energy Group
   (iii)CT Weatherproof Insulation
   (e) Public Outreach - done

   b. Multifamily – working on now with new MOU*
   i. Set benchmark
   ii. Greenwich Housing Authority
   iii. Greenwich Property Owners Association, Inc

2. **Town of Greenwich Facilities** (Town staff team):

   a. Complete Benchmarking – completed and presented to Town in Feb 2017
   i. Gas account information received
   ii. Eversource to finish entering data into portfolio manager (Fall 2016)
   iii. Schedule appointment with Greenwich to review results of benchmarking

b. **Select Buildings for Walkthrough Audits – <u>Town Hall selected – audit conducted Feb 2017. Contacted by Eversource on Aug. 21, 2017 to set up a meeting so that they could present the audit to the Town.</u>**
c. Coordinate Energize CT with planned new construction – <u>have initiated process with Eversource (eg. Bruce Museum, New Lebanon School)</u>
d. Outdoor lighting

3. **Commercial, Industrial, and Institutional Customers** (Conservation Energy Committee) – <u>Launching in Fall of 2017</u>

a. Set Benchmark
b. Engage and discuss opportunity with all top quartile energy use customers
c. Review virtual audit data with customers as appropriate
d. Develop outreach program
   i. Investigate conducting a small business outreach event -
   ii. Speaking opportunity/co-hosting event with Greenwich Chamber of Commerce

III. **Alternative Energy** (Conservation Energy Committee) – <u>re-engaged with CT Green Bank in summer 2017 as part of this larger planning effort</u>

a. Solar
   i. ZREC
   ii. CPACE
   iii. Residential

b. Other renewables
   i. Geo-thermal

<u>* Because of the success shown above, The Town and Eversource now engage in strategic planning for Energy Efficiency resulting in an MOU with Eversource as outlined in presentation made to the Town in May 2017. A committee has been formed and first strategic planning charrette is set for September 2017. Although Eversource recommended doing this for Town buildings, at the Town's request, this will also look commercial and residential buildings in Town. Will also continue to explore working with Eversource and the Ct Green Bank, not only on energy efficiency but on modernizing the grid.</u>

<u>Note: all items in red and underline added after the Sept 16 adoption of this strategy.</u>

ATTACHMENT B

2017 COMPREHENSIVE ENERGY STRATEGY

EXECUTIVE SUMMARY

Draft: July 26th, 2017

CT GENERAL STATUTES SECTION 16a-3d

Connecticut Department of Energy and Environmental Protection

EXECUTIVE SUMMARY

The Connecticut Department of Energy and Environmental Protection (DEEP) has prepared this update to Connecticut's Comprehensive Energy Strategy (CES) to advance the State's goal to create a cheaper, cleaner, more reliable energy future for Connecticut's residents and businesses. By statute (see Appendix A), DEEP is required to periodically update the CES to assess and plan for all energy needs in the state, including, but not limited to, electricity, heating, cooling and transportation.

Since the publication of Connecticut's first CES in 2013, the State has advanced policies and programs that have put the State on a path to reduce energy costs, improve system reliability, and minimize environmental impacts for its residents and businesses. Connecticut has achieved significant progress. For example, since 2013 DEEP has:

- Directly procured commitments of renewable energy generation and energy efficiency that equal the generation of a large power plant, at competitive pricing.
    - Specifically, the state has procured over 400 megawatts (MW) of DEEP-solicited small scale renewable energy and energy efficiency resources, and over 400 MW of large-scale renewable energy projects, 90 MW of which will be located in Connecticut.
    - The price of these selected grid scale bids dropped by nearly half compared to procurements in 2012 and 2013.
    - Procurement of energy efficiency as a resource moves the energy efficiency resource standard to a level on par with other generation sources, truly exemplifying the value of efficiency as a resource equivalent to supply.
- Developed a first-in-the-nation statewide microgrid program to build local resiliency for electrical load in critical community operations.
    - Program implementation now includes five operational microgrids and five in development.
- Established a Governor's Council on Climate Change to ensure the State meets its greenhouse gas (GHG) reduction goals.
- Launched a Shared Clean Energy Facility pilot program, with DEEP selecting over 5 MW of solar that will have a dedicated subscription target of low- and moderate-income consumers.

- Advanced development of renewable energy generation and supported lower electricity bills for state, municipal, and agricultural customers through virtual net metering.

- Converted 39,104 residential customers to natural gas for heating, and 12,021 commercial and industrial customers to natural gas for generation or other processes between 2014 and 2016.

- Catalyzed residential and commercial investments in energy efficiency across the state through implementation of Connecticut's award-winning Conservation and Load Management Plan (C&LM Plan), contributing to Connecticut's economy, and fueling an energy efficiency industry with 34,000 jobs in Connecticut.
    - These investments have empowered state residents to collectively save more than $140 million annually, Connecticut's businesses to save more than $115 million annually, and Connecticut's state agencies to save $6 million annually.
    - Investments are spread across millions of projects statewide, including in more than 20,000 low-income homes annually and at thousands of businesses, large and small.
    - Investments include utilities and others providing low or no interest financing for heating equipment with simplified applications and on-bill repayment, and market-based incentives that transform energy use.
    - Connecticut became the first state to implement the U.S. Department of Energy's Home Energy Score labeling system on a statewide voluntary basis, producing over 21,000 scores to date.

- Launched the EVConnecticut program to:
    - Provide grants for charging and alternative fueling stations to make Connecticut a range-confident state, and
    - Deploy point-of-sale vehicle rebates through the Connecticut Hydrogen and Electric Automobile Purchase Rebate (CHEAPR) program—supporting the purchase of 1,300 EVs.

- Launched CT*fastrak* bus rapid transit (BRT) service, doubling the ridership in corridor to between 12,000-16,000 weekday trips and helping riders avoid rush-hour congestion.

- Released Let's Go CT!, Governor Dannel Malloy's transportation Call to Action representing 30-year vision for Connecticut's best-in-class transportation system.

The State will continue to build upon this foundation to transform how we produce, distribute, and consume energy to achieve Connecticut's long-term vision of a zero-carbon economy. This transformation will take many years to implement and requires developing a forward thinking framework with specific plans and recommendations for the near term.

With this in mind, the 2017 update of the CES is guided by the goal of cheaper, cleaner, more reliable energy. Connecticut energy policy must:

- Align with and support the State's broader environmental policies to meet clean air, clean water, land conservation and development, and waste reduction goals;
- Put the State on a clear path to meet the Global Warming Solutions Act to reduce GHG emissions 10 percent below 1990 levels by 2020 and 80 percent below 2001 levels by 2050;
- Focus on grid modernization, strategic electrification, increasing efficiency, and improving reliability and security;
- Increase energy affordability and economic security to help strengthen the State's economy now and into the future;
- Maintain equitable access to the benefits of clean and efficient energy generation and transportation options.

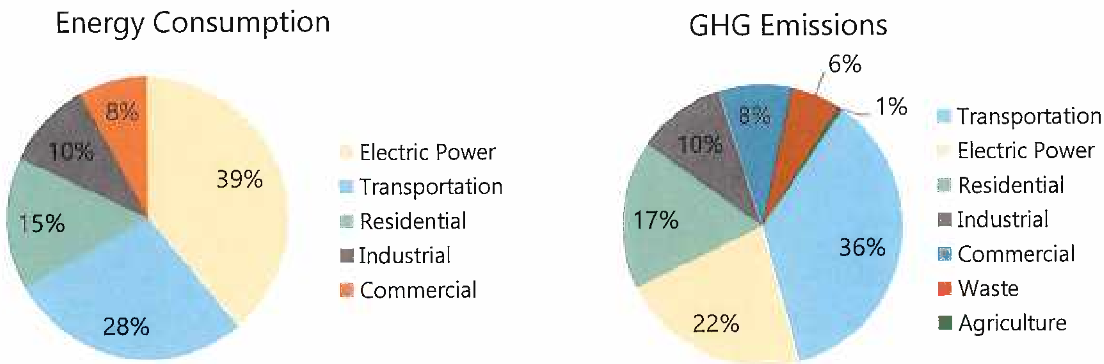
Guided by these principles, this CES offers a series of goals and strategies that reflect lessons learned and respond to new conditions within the three energy end-use sectors; electricity power, buildings, and transportation. These strategies and goals advance the State's long-term vision by calling for continued investment in clean energy resources, grid-modernization, increasing energy efficiency in buildings and transportation, and accelerating progress to decarbonize the energy sector.

Energy Policy that Advances Climate Goals

Energy consumption across all fuels and sectors accounts for 93 percent of the GHG emissions in Connecticut. Across energy usage sectors, transportation is the largest contributor of emissions, accounting for 36 percent, with the electric power sector following at 22 percent (see Figure ES1). As the State's single largest source of emissions, Connecticut's transportation sector emissions are well above the national average where emissions from the transportation sector are 27 percent and the electric power sector makes up 29 percent.[1]

[1] U.S. EPA's inventory of U.S. Greenhouse Gas emissions and Sinks: 1990 -2015, April 2017. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2015

FIGURE ES1: Connecticut Energy Consumption and GHG Emissions by Sector



Source: United States Energy Information Administration

This difference in emissions contributions for the electric power and transportation sectors can be attributed to Connecticut, and the New England region as a whole, transitioning electric power generation from carbon intensive fuel sources such as coal and oil to less carbon intensive fuel sources such as natural gas and renewables.[2] The region's grid operator, ISO New England, attributes this transformation to four primary factors: public policies and programs, economics, innovation, and customer choices.[3]

DEEP's most recent GHG inventory analysis shows that the State has reduced emissions 4 percent below 1990 levels and 14 percent below 2001 levels.[4] Although Connecticut's progress in reducing GHG emissions has been successful, far deeper cuts are needed in the coming decades to meet the Global Warming Solutions Act's (GWSA) 2050 target. The State must continue to move swiftly to decarbonize its energy supply across all sectors.

In an analysis completed by the Governor's Council on Climate Change (GC3), the business-as-usual reference case shows emissions from the electric power sector will continue to decline. However, while emissions from the transportation sector will remain almost constant at 35 percent

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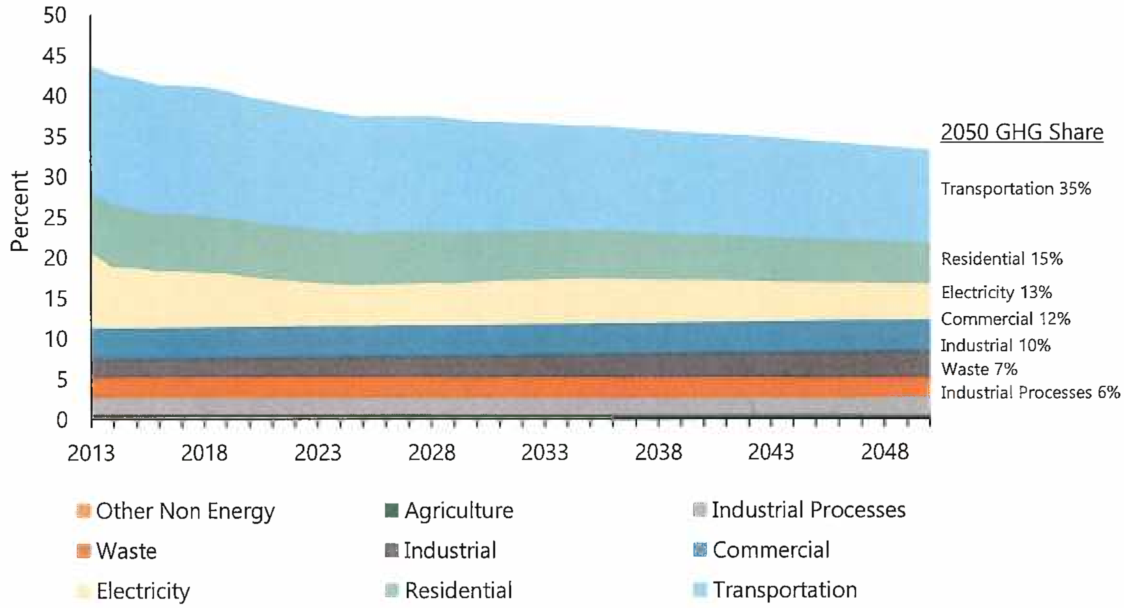
[2] New England Power Grid 2016-2017 Profile, ISO New England, https://www.iso-ne.com/static-assets/documents/2017/01/ne_power_grid_2016_2017_regional_profile.pdf

[3] Grid in Transition: Opportunities and Challenges, ISO New England Regional Outlook, https://www.iso-ne.com/about/regional-electricity-outlook/grid-in-transition-opportunities-and-challenges

[4] 2013 Connecticut Greenhouse Gas Emissions Inventory, CT DEEP, 2016 http://www.ct.gov/deep/lib/deep/climatechange/2012_ghg_inventory_2015/ct_2013_ghg_inventory.pdf

FIGURE ES2: Economy-wide GHG Emissions Business as Usual Reference Case



*The agriculture and non-energy sectors represent 1% and .3% respectively, of total emissions in 2050

of economy-wide GHG emissions through 2050.[5] The residential, electric power, commercial, and industrial sectors follow at 15, 13, 12 and 10 percent respectively by 2050 (Figure ES2).

To achieve the long-term vision of a developing a zero-carbon economy, improving building efficiency, and reducing vehicle miles traveled can help decrease the use of carbon-intensive fuels. But ultimately, widespread electrification of building thermal loads (cooling and heating) and the transportation sector is required. Consequently, by 2050 electricity becomes the dominant source for our energy supply and makes decarbonization of the electric power sector the cornerstone to the success of achieving a carbon-free economy.

It is important to note that Connecticut's ambitious emissions reduction goals cannot be achieved by government alone. Private actors including businesses, civic and advocacy groups, private citizens, religious organizations, associations, and colleges and universities play a critical role. Collaborative partnerships, private investment, and technology innovation is paramount to achieving the necessary reductions. Climate change solutions that go beyond government action

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[5] Governor Dannel P. Malloy's Executive Order 46 (4-22-15) established the Governor's Council on Climate Change to examine the efficacy of existing policies and regulations designed to reduce GHG emissions and identify new strategies to meet the established emission reduction targets.

Governor's Council on Climate Change

On Earth Day 2015, Governor Malloy issued Executive Order 46, creating the Governor's Council on Climate Change (GC3). The Council is composed of 15 members from state agencies, quasi-state agencies, companies, and nonprofits. Governor Malloy tasked the Council with:

- establishing interim goals that will guide the state to the 2050 emission reduction target;
- annually monitoring statewide GHG emissions to determine if the state is poised to meet its 2050 target and any established interim goal(s);
- examining the efficacy of existing policies and regulations designed to reduce GHG emissions; and
- recommending new policies, regulation, or legislative actions that will assist in achieving established emission-reduction targets.

Council members are currently in the process of analyzing greenhouse gas emission reduction scenarios to inform their recommendations on strategies that lead to long-term emissions reductions and to ensure that the state is on a path to meet its Global Warming Solutions Act goal of 80 percent below 2001 levels by 2050.

For more information on GC3 activities: www.ct.gov/deep/GC3

will help stimulate the economy and build strong, vibrant, and resilient communities across the state.

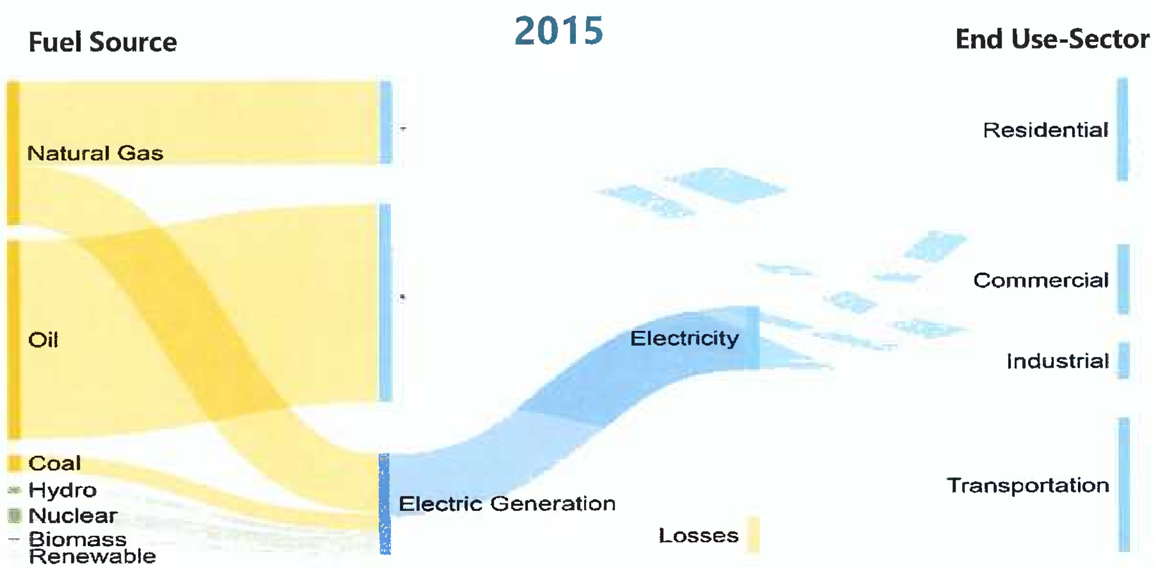
Pathway to Grid Modernization and Decarbonization

Connecticut's energy vision identifies a pathway for meeting our environmental goals while capturing the benefits of investing in renewable energy sources and minimizing our dependence on commodities subject to price volatility. According to United States Energy Information Administration data for 2015, Connecticut's businesses and residents spend over $13 billion on energy produced from petroleum and natural gas annually. These costs are spread between the residential sector at 36%, the commercial sector at 22%, the industrial sector at 7% and the transportation sector at 35%. Continued reductions in energy consumption from each sector is essential for Connecticut to reach energy affordability and environmental sustainability goals.

The following figure provides illustrative energy flows for 2015 (Figure ES3) showing Connecticut's energy consumption of the regional mix by fuel type for electricity generation, and also depicts energy losses. The left side of the graphic identifies the primary type of energy supply (natural gas, oil, coal, hydro, nuclear, biomass and renewables). The height of each bar corresponds to the amount of energy from each source. The figure also depicts portions of the energy flow that is transformed into electricity, while others are used directly in end use sector buildings (residential, commercial, industrial and transportation).

To meet its 2050 greenhouse gas emissions reduction target, transformation of these energy flows is necessary, including increased renewable energy generation and energy storage, deployment of electric vehicles, and energy efficiency. As part of this transformation, fossil fuel use will decline over time and be displaced with renewable generation and electric end use increases. These policies are being evaluated by the Governor's Council on Climate Change as they provide a recommendation on an interim greenhouse gas emissions reduction target.[6]

FIGURE ES3: Connecticut Energy Flows in 2015



[6] Connecticut's Global Warming Solutions Act requires the state to reduce greenhouse gas emissions by 10% from 1990 levels by 2020 and 80% from 2001 levels by 2050. Conn. Gen. Stat. Sec. 22a-200a.

Energy Policy that Advances Grid Modernization Goals

Connecticut's grid of the future must achieve the broad goals of delivering cheaper, cleaner and more reliable energy while addressing increased electricity demand. It will need to integrate distributed generation, and expand energy storage and demand response at the lowest cost for electric ratepayers. The grid must therefore be supported by a secure network that can effectively blend both bulk electric grid operations and highly distributed generation, while remaining resilient to weather and climate events, and resistant to cyber assaults. The system will also need to continue supporting community resiliency and enabling new deployment and interconnection of micro-grid systems. Increased deployment and integration of advanced technologies such as energy storage, will enhance flexibility of grid operations. This will also encourage cost savings, especially during times of peak electrical demand, and increase reliability and customer response.

To ensure steady progress in meeting the state's GHG reduction goals and to put the state on a pathway to decarbonize the electric sector, this Strategy assumes that at a minimum, an extension of the Renewable Portfolio Standard (RPS) to 30 percent by 2030 will be required, along with consideration of the role of other carbon-free resources such as nuclear and large-scale hydroelectric.

Key strategies to modernize the grid include:

- Renew progress, with leadership from the Public Utilities Regulatory Authority (PURA), on smart grid implementation, including variable pricing and advanced meters.
- Continue to promote the development of microgrids and energy storage technologies.
- Work with the utility companies to ensure the continual improvement of cyber-security measures.

As Connecticut continues to increase its level of investment in renewables, it must ensure that investments are made cost-effectively and for the benefit of all ratepayers. This Strategy calls for the majority of RPS obligations to be met using grid-scale resources, which have dramatically reduced in price for all ratepayers, and advocates changes to behind-the meter programs that will maximize the impact of ratepayer dollars on the development of renewables, while improving transparency.

Key strategies to deploy renewables and decarbonize the electricity supply:

- Expand the RPS to achieve 30% Class I by 2030.
- Phase down biomass and landfill gas in Class I of the RPS.
- Evaluate the future of zero-carbon resources as they apply to meeting GHG reduction goals.

- Revise the cost-structure for net energy billing to maximize the impact of ratepayer investment, and ensure that investment is sustainable over the long-term.
- Prioritize grid-scale, DEEP-run procurements for renewables and energy efficiency in order to optimize zero-carbon resource deployment at the lowest cost to consumers, and address siting and land-use pressures through the development of a working group.

Energy Efficiency and Strategic Electrification

Today, over 80 percent of Connecticut households and commercial and industrial buildings are heated using fossil fuels.[7] Accomplishing Connecticut's GHG emissions reductions goals will require predictable and sustained investments in reducing energy waste and moving to clean sources of electric power, with substantial electrification of our thermal processes in buildings. Moving our buildings to renewable thermal sources, and to efficient electric thermal technologies will require strategic, phased in deployment.

As electric demand may subsequently increase to meet expanded thermal load needs, the ability to maintain progress in energy efficiency and curb peak energy demand will become increasingly important. Energy efficiency can reduce both consumption and peak demand, avoid transmission and distribution costs (T&D), and mitigate price effects in the wholesale market. Energy savings from efficiency investments are currently being achieved at a cost of about 4.5 cents per kWh of lifetime electric savings.[8] Therefore, not only is it a low-cost energy resource that delivers savings to ratepayers, but also a critical method for offsetting and neutralizing the increased demand from expanded electrification of home heating and cooling.

Accomplishing this transition will involve significant planning, deployment, and changes to both institutional and regulatory frameworks. Key 2017-2020 strategies for energy efficiency include actions that will:

- Continue to predictably and sustainably invest in energy efficiency and prioritize efficiency as a resource through procurement of efficiency as a supply resource, committed investments in the statewide conservation and load management plan, and through selling efficiency gains to meet the regional grid's capacity requirements.
- Enhance the performance of built infrastructure and the energy productivity of industrial processes, including through weatherization, efficiency audits, and building codes.

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[7] Gronli et. al. 2017. *Feasibility of Renewable Thermal Technologies in Connecticut: Market Potential.*

[8] Molina, Maggie, "The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs", Publications, American Council for an Energy-Efficient Economy, 2014, http://aceee.org/research-report/u1402.

- Continue to expand active energy demand management through control technologies, pricing signals, and standardized two-way communication, and access to advanced meters.
- Pursue strategic electrification, including encouraging the utility companies to promote the installation of efficient heat pumps, initially focusing on buildings currently heated by electric-resistance heating systems and on new construction, then eventually replacing combustion heating systems as the electric power sector becomes cleaner.

Clean and Accessible Transportation Options

Transportation is an integral part of Connecticut's socioeconomic fabric. Connecticut's transportation system and infrastructure encompass an extensive range of multimodal elements – from roadways and highway facilities, pedestrian and bicycle accommodations, to bus transit systems, passenger and freight railways, airports, deep water ports, and even ferry landings. This infrastructure connects residents and visitors to families, friends, services, jobs and communities. It also enables the movement of retail goods, raw materials, and other commodities in, out, and around the state. The reliability of the state's transportation system and supporting infrastructure, as well as the energy resources necessary to operate that system have a direct impact on Connecticut's economy and the quality of life for its 3.5 million residents and their local communities. To effectively enhance quality of life, minimize environmental impacts, and foster continued economic growth, it is critical that the state provides a safe, reliable and efficient transportation system that can accommodate future growth in population, tourism, business, and recreation.

Transportation energy consumption and emissions are a function of vehicle fuel efficiency, the carbon content of the fuel source and vehicle miles traveled (VMT). A sustainable and low-carbon transportation energy future will require significant refinements in order to provide increased mobility options to citizens and businesses and ensure that the state achieves its GHG emissions reduction targets. As the state's largest contributor to GHG emissions, steep reductions from the transportation sector will be required to ensure Connecticut meets its Global Warming Solutions Act goal of reducing emissions 80 percent below 2001 levels by 2050.

In this 2017 CES, the transportation recommendations put forth embrace solutions that go beyond adding roadway capacity to address population growth and economic expansion, but rather, aim to put Connecticut on a clear path to achieve state emission reduction targets, increase connectivity, user flexibility, and equitable access to efficient and clean transportation options, improve resilience to fuel price volatility, enhance economic growth, and create desirable communities.

Key 2017-2020 strategies for the transportation sector include:

- Develop an Electric Vehicle Roadmap that takes a comprehensive approach to expanding alternative fueling infrastructure and vehicle purchasing, addresses regulatory frameworks needed to support deployment, and enhances current outreach and education efforts.
- Support current state planning efforts that advance smart-growth and transportation-oriented development.
- Embrace technological advances, innovative models, and creative partnerships that improve access to a wider array of clean transportation options.
- Work with regional partners in the public and private sector to advance a clean, efficient, and accessible transportation network.

Process to develop 2017 Strategy

DEEP held a series of scoping meetings, informational meetings and workshops on specific topics to provide inclusive input on the CES.

- May 24, 2016: DEEP held a scoping meeting to receive stakeholder feedback on the major topics to include in the upcoming CES.
- October 27, 2016: DEEP held an informational meeting on demand resource management at the regional and local level
- November 3, 2016: DEEP held an informational meeting on air- and ground-sourced heat pumps, solar water heating, and biodiesel as thermal fuel in the state and region.
- January 10, 2017: DEEP co-convened with the Department of Agriculture a workshop to discuss state renewable energy programs and their intersection with environmental, agricultural, and land use policies.
- February 15, 2017: DEEP held an informational meeting on implementation of DEEP's strategies to reduce and improve energy use at state buildings.

DEEP received public input on all of these topics and incorporated the feedback into the CES.

OVERVIEW OF RECOMMENDED GOALS & STRATEGIES

The Table below summarizes the recommendations, organized by Chapter and around key goals for each sector and the specific strategies proposed to meet them.

CHAPTER ONE: ELECTRIC POWER SECTOR	
Goal 1: Align existing programs supporting renewable and zero carbon resources with renewable portfolio standards and global warming solutions act goals.	
E.1.1	Expand the RPS to achieve 30 percent Class I renewables by 2030.
E.1.2	Phase down biomass and landfill gas RECs in Connecticut's Class I of the RPS.
E.1.3	Achieve a sustainable balance between behind the meter programs and grid-scale procurements supporting Class I Renewables to expand clean energy at the least cost for ratepayers.
E.1.4	Increase transparency and certainty in the cost structure for net energy billing by creating renewable energy tariffs.
E.1.5	Evaluate the conditions around utilizing a diverse zero-carbon generation mix to meet our greenhouse gas emissions reduction goals.
E.1.6	Pursue goals of the shared clean energy facility program through multiple avenues based on lessons learned from the pilot program.
E.1.7	Strengthen voluntary renewable product verification in the competitive electric supplier market.
E.1.8	Convene a working group to implement best practices to optimize siting of renewable facilities on appropriate sites in Connecticut.
Goal 2: Continue to support regional and state reliability and resiliency efforts	
E.2.1	Support ISO-NE in addressing regional winter natural gas generation reliability issues.
E.2.2	Continue to deploy community microgrids to support statewide resiliency goals in strategic locations and support the Energy Assurance Plan.
E.2.3	Ensure coastal resiliency of substations and other critical grid infrastructure to support DEEP's flood management goals.
E.2.4	Continue to identify and explore grid modernization initiatives.

CHAPTER TWO: BUILDINGS SECTOR	
Goal 1: Prioritize energy savings as both a financial and energy resource	
B.1.1	Procure energy efficiency as a resource.
B.1.2	Enhance competitiveness of Connecticut's businesses with customized energy efficiency investments.
B.1.3	Reduce the energy affordability gap in low-income households.
B.1.4	Improve financial programs to increase access to clean and efficient energy improvements.
B.1.5	Maximize consumer demand for energy efficiency by increasing awareness and understanding of its value.
B.1.6	Evaluate current cost-effectiveness testing methods for accurate reflection of all resource costs and benefits.
B.1.7	Ensure equitable efficiency investment for delivered heating fuel customers through equitable conservation charges.
Goal 2: Improve the performance and productivity of buildings and industrial processes	
B.2.1	Ensure application of and compliance with current building energy codes and product efficiency standards.
B.2.2	Strategically sequence deployment of cleaner thermal fuel choices to transition buildings from fossil fuels.
B.2.3	Continue increasing the rate of home weatherization and assessment, statewide.
B.2.4	Address the unique needs of multifamily buildings for implementing cost-effective, clean and efficient upgrades.
B.2.5	Reduce energy waste by using combined heat and power, where it is cost-effective, in commercial and industrial applications.
B.2.6	Reduce energy waste at water and wastewater treatment facilities.
B.2.7	Evaluate applicability of district heating and thermal loops in high density areas.

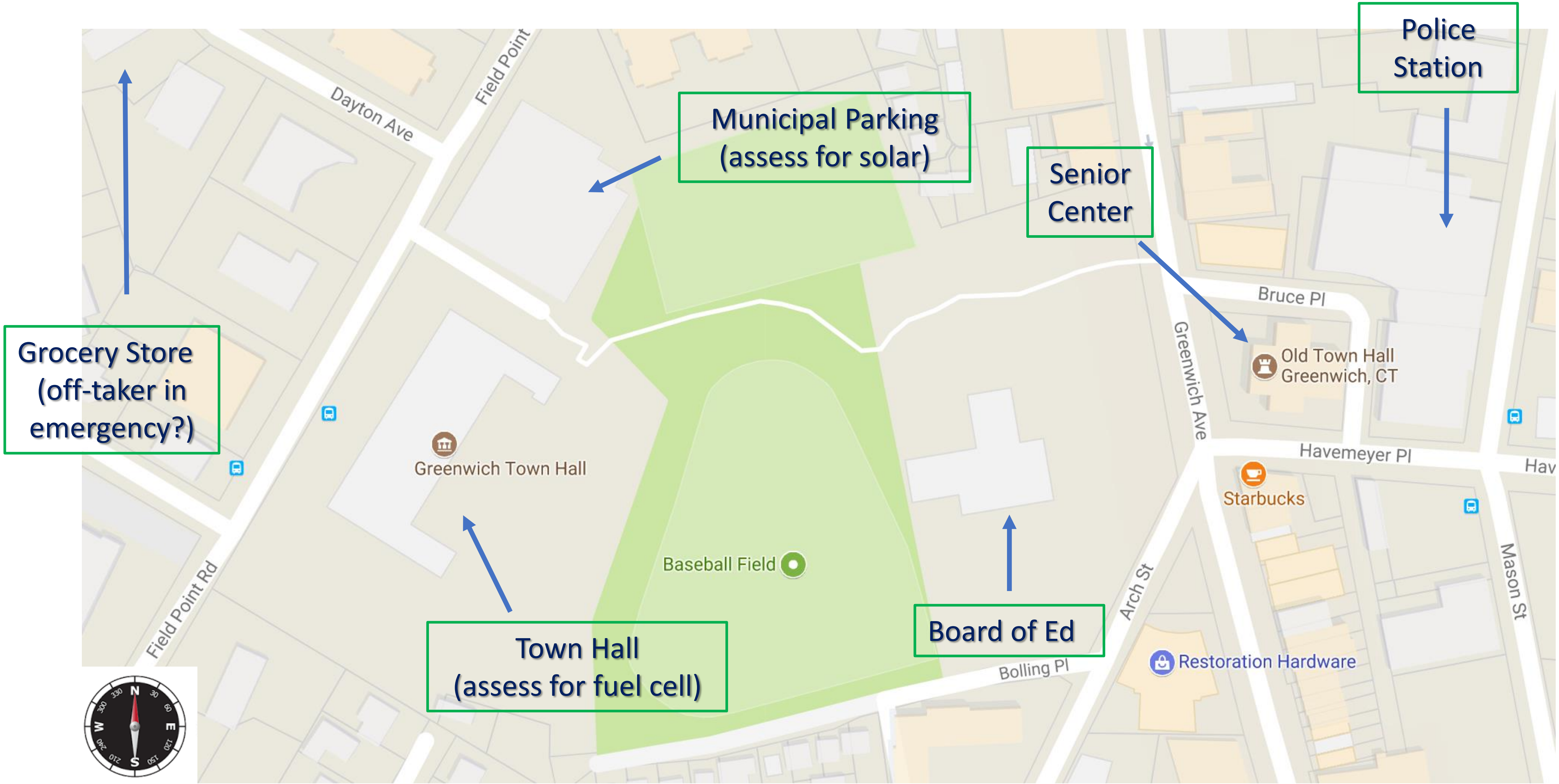
B.2.8	Inventory state buildings and their energy usage patterns to identify greatest energy savings opportunities.
B.2.9	Support diversification of the heating oil delivery industry's products and services.
Goal 3: Continue prioritizing grid load management to reduce peak demand	
B.3.1	Target peak demand reductions.
B.3.2	Increase and standardize two-way advanced meter communication.
B.3.3	Optimize economic signals and incentives for demand response to recognize shifts in demand from expanding electrification of heating and transportation.

CHAPTER THREE: TRANSPORTATION SECTOR	
Goal 1: Put the State on a strategic pathway to decarbonize the transportation sector	
T.1.1	Develop an Electric Vehicle Roadmap to accelerate the adoption of low and zero-emissions vehicles and strengthen alternative fueling infrastructure.
T.1.2	Advocate for the implementation of federal vehicle fuel economy standards and maintaining LEV, ZEV, and GHG programs.
T.1.3	Educate and engage citizens and employers on the benefits of clean and efficient transportation options, including the advantages of transportation demand management measures.
Goal 2: Facilitate state planning to advance smart-growth, transit-oriented development, and mixed-use planning that leads to energy and emissions reductions.	
T.2.1	Support the long-term vision and initiatives in Let's Go CT!
T.2.2	Encourage and support smart-growth, transportation-oriented development, mixed-use planning, and development efforts that improve connectivity and accessibility to public transit.
Goal 3: Develop and support strategic partnerships to improve access to a wider array of transportation options	
T.3.1	Embrace technological advances and private-public partnerships that improve mobility and access to clean modes of transportation.

T.3.2	Participate in regional partnerships and initiatives to advance a clean and efficient transportation network throughout the region.

ATTACHMENT C

Proximity of Town of Greenwich Buildings



ATTACHMENT D

EVERSOURCE ENERGY

Town of Greenwich Meeting
Non Transmission Alternative Analysis
(Distributed Generation, Energy Storage and Demand Response)

Kenneth Bowes
Vice President Engineering
December 12, 2016

Today's Topics

EVERSOURCE ENERGY

- Use of "non-Transmission Alternatives" to meet the Need
  - Size of the Need to Replace new Substation
- Target Areas – Geographic View
- Solar PV Requirements to Fill the Need
- Fuel Cells Requirements to Fill the Need
- Energy Storage Requirements to Fill the Need
- Demand Response Requirements to Fill the Need
- Size of the Need to offset Future Load Additions

- Appendix
  - Distributed Generation in Greenwich
  - Brooklyn Queens Demand Management Program and comparison to Greenwich Initiatives
  - Bridgeport Fuel Cell Installation

Size of the Need to Replace new Substation

EVERSOURCE ENERGY

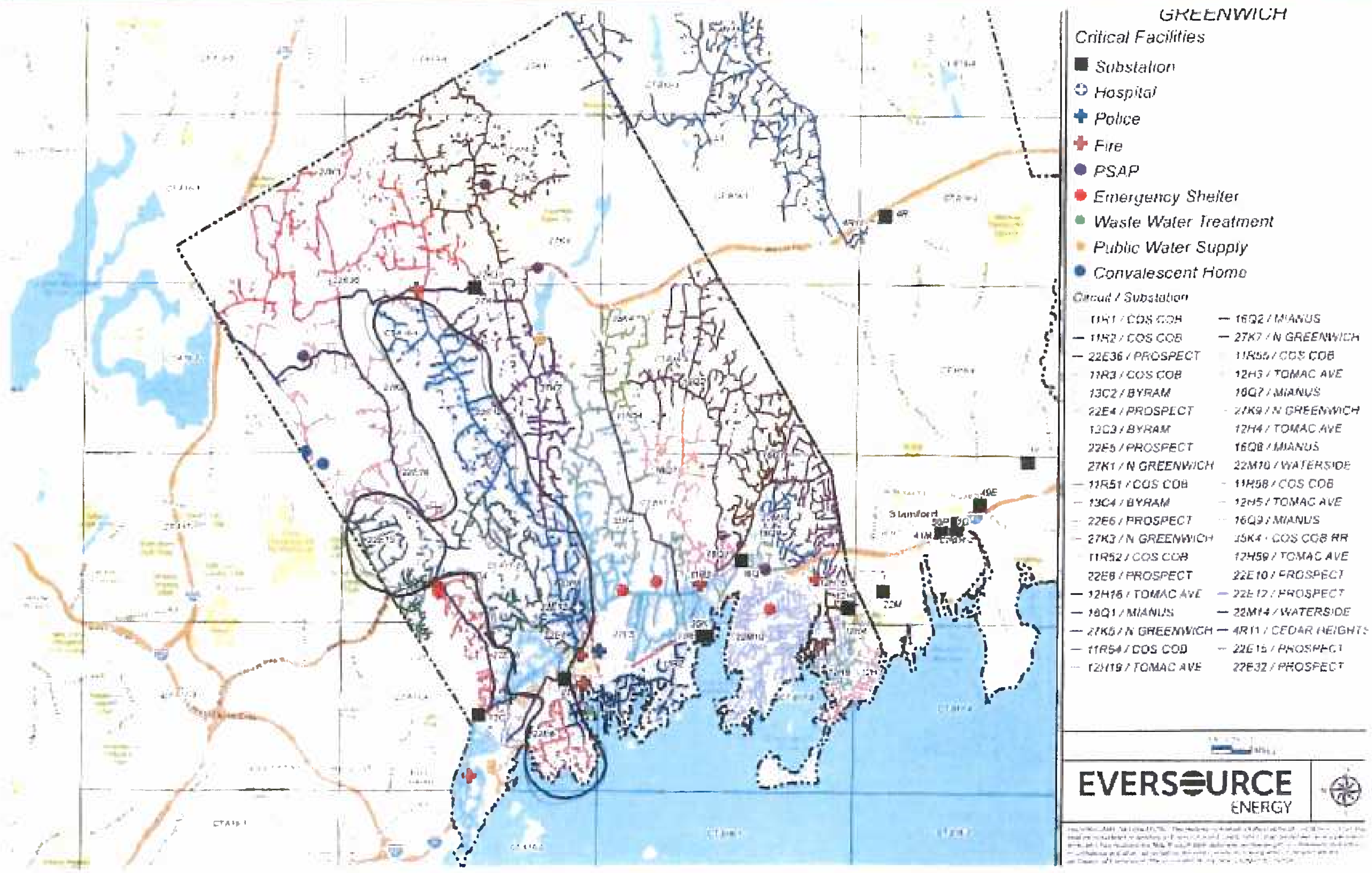
<u>Town's desire to improve overall grid by:</u>

- Approximately 30MVA of load reduction required to address the Substation Project Need
  - Solar PV Requirements
  - Fuel Cells Requirements
  - Energy Storage Requirements
  - Demand Response Requirements

- Energy Efficiency (EE)
  - Efforts well underway
  - Previously agreed that EE alone does not solve the Project need

Target Area for Development

EVERSOURCE ENERGY



Company Confidential

Solar PV - Requirements to Fill the Need

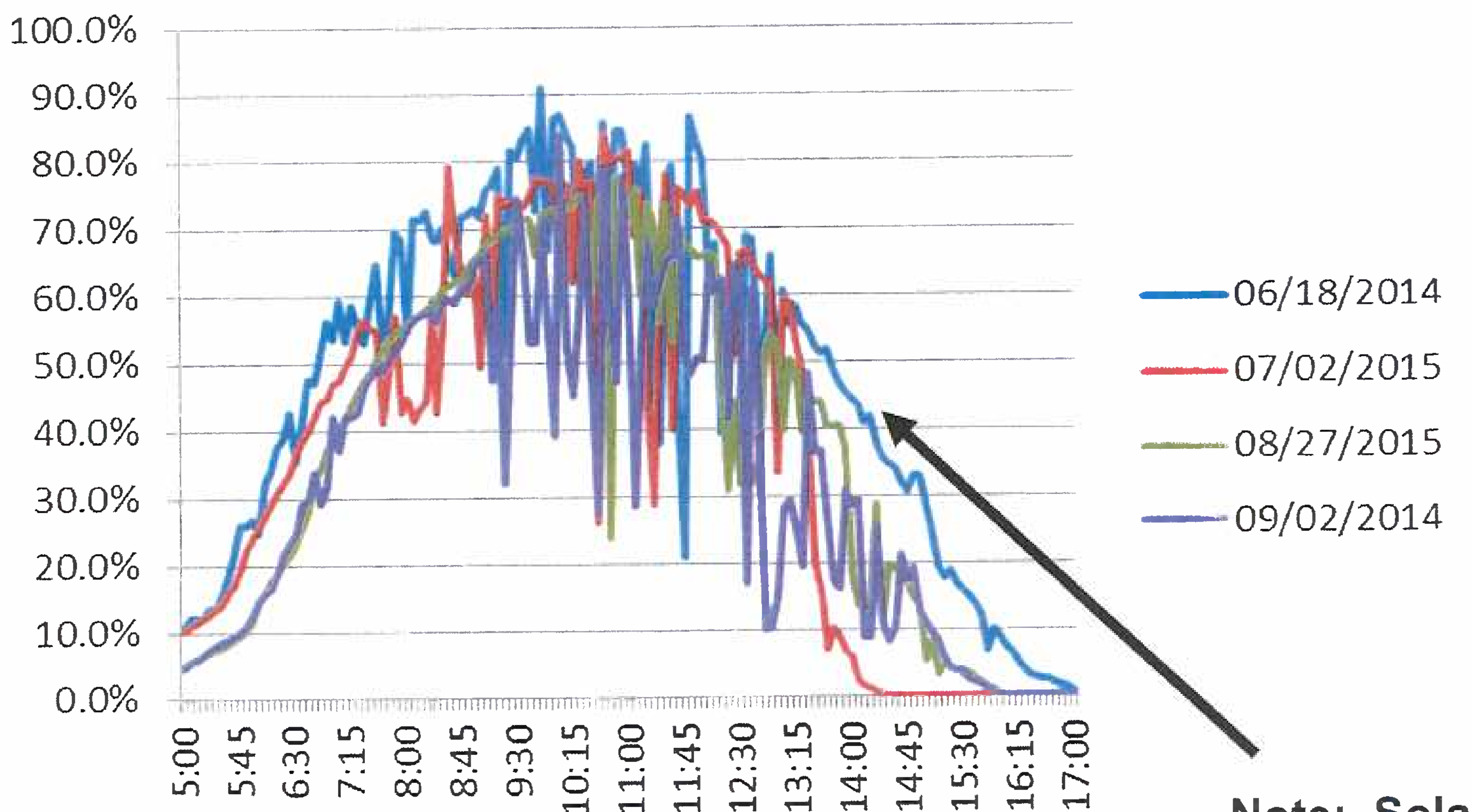
EVERSOURCE ENERGY

- Solar PV capacity factor 15-18%
- Initial target of 30MW of Solar PV would require approximately 5 acres per MW = 150 acres of rooftop or ground based systems
- Projected to supply up to 15MW during peak time hours
- Would need Energy Storage to “firm up” the variability and shift output later in the day to 4-6 pm Greenwich peak hours
- Estimated cost of $105M (based upon 1-3 MW solar farms)

Solar PV - Requirements to Fill the Need

EVERSOURCE ENERGY

Typical PV production profile



Note: Solar PV output at time of peak

Fuel Cell - Requirements to Fill the Need

EVERSOURCE ENERGY

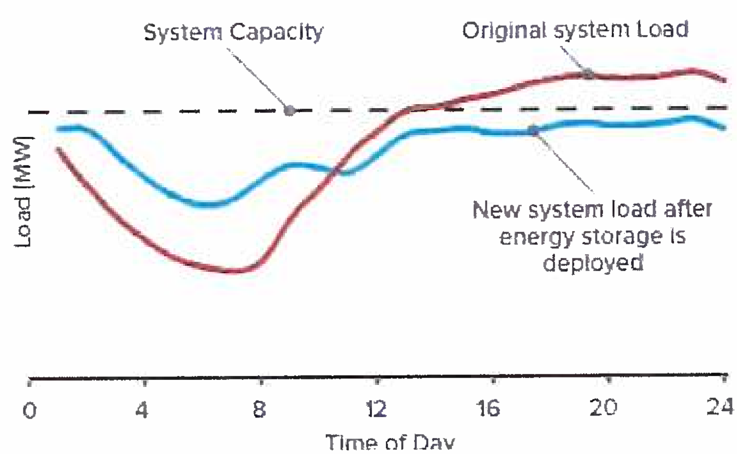
- Fuel Cell capacity factor 95-98%
- Initial target of 10MW of Fuel Cells would require approximately 15-20 installations
  - Could use one or more larger utility type installations of 2-5 MW size to reduce number of units needed
- Projected to supply up to 10MW during peak time hours
- Would need gas supply
- Estimated cost of $78M

Source: Bloom Energy

Energy Storage - Requirements to Fill the Need

EVERSOURCE ENERGY

- Energy Storage capacity factor 95-98%
- Initial target of 5MW of Energy Storage would require approximately 2-4 installations
- Projected to supply up to 5MW during peak time hours – 2 to 4 hours needed
- Estimated equipment cost of $15M
  - Site development costs would be incremental

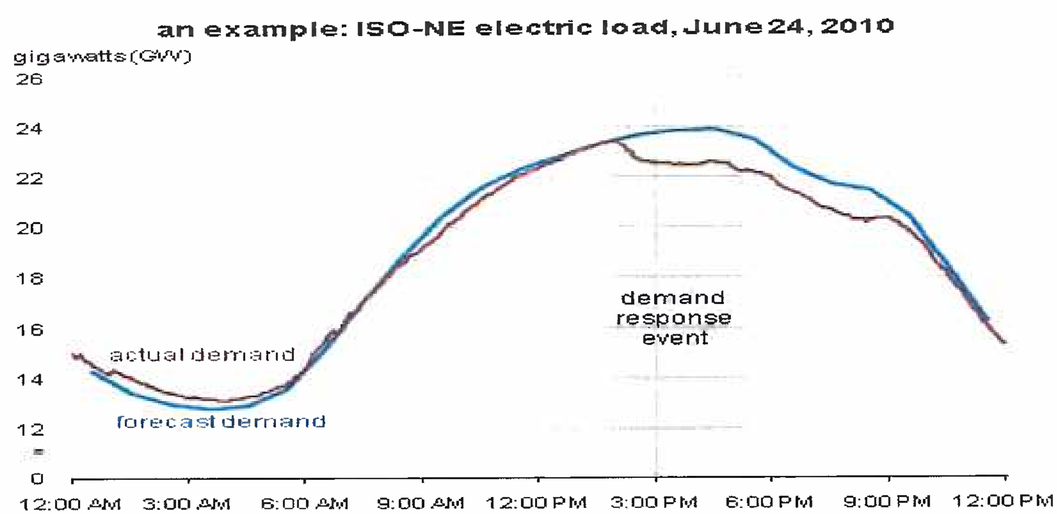


Company Confidential

Demand Response - Requirements to Fill the Need

EVERSOURCE ENERGY

- Demand Response capacity factor 50-75%
- Initial target of 2MW of Demand Response would require approximately 100+ installations
- Projected to supply 1 to 2MW during peak time hours – 2 to 4 hours needed
- Estimated equipment cost of $1M



Company Confidential

Comprehensive Non-Transmission Alternatives Solution

EVERSOURCE ENERGY

	Size of Solution (in MW)	Locations/Customers	Costs (in millions)
Solar PV (50% output at peak)	30 MW	10-15	$105
Fuel Cells	10 MW	10 – 20	$78
Energy Storage	5 MW	2-4	$15
Demand Response	1 MW	100+	$1
Total (with capacity factor weightings)	31 MW	120+	$199M

Future - Size of the Need to offset Load Additions

EVERSOURCE ENERGY

- 1-2 MW of Non-Transmission Alternatives would be needed each year going forward
- New Construction requirements to include Distributed Energy Resources
- Focus on Town of Greenwich Facilities (see next slide)
  - Continue with Energy Efficiency measures
  - Inventory of Town Facilities
  - Establish goals for Town Facilities – ultimately to meet up to 15MW of need (2X existing peak demand of Town Facilities)

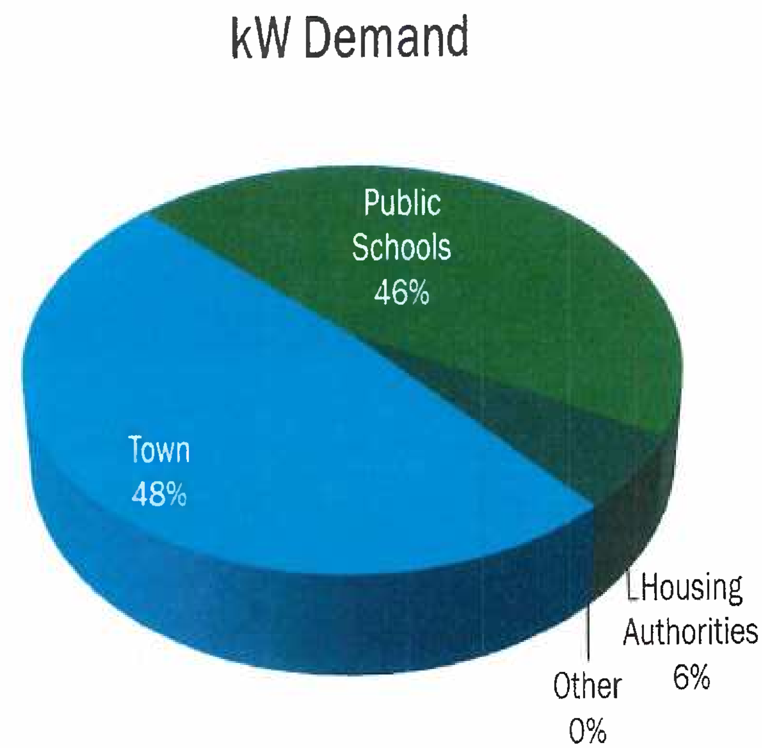
Town of Greenwich Facility Profile

EVERSOURCE ENERGY

Sector	Quantity of Accounts	kW Demand
Town	204	3,682
Public Schools	23	3,471
Housing Authorities	16	439
Other*	5	-
Total	248	7,592

Top five facilities - typical peak KW demand

TOWN FACILITY	STREET_NAME	KW DMD
GREENWICH HIGH SCHOOL	HILLSIDE RD	1,300
GREENWICH SEWER DEPT	GRASS ISLAND RD	700
TOWN OF GREENWICH DEPT OF PUBLIC WORKS	FIELD POINT RD	500
TOWN OF GREENWICH DEPT OF PUBLIC WORKS	PARSONAGE RD	500
TOWN OF GREENWICH DEPT OF PUBLIC WORKS	BRUCE PL	300
Total peak demand - typical		**3,300**



* Parks & Recreation, DPW

Note: Housing Authority Data excludes individual apartment use and account quantities

Town of Greenwich - DER Action Plan

EVERSOURCE ENERGY

- Suggested Steps to create DER action plan for town facilities:
  - Complete energy benchmarking already underway and prioritize energy efficiency opportunities
  - Overlay DER opportunity and feasibility on EE benchmarking results:
    - Roof orientation and physical condition to accommodate a PV system
    - Available town owned land area suitable for a ground mounted system
    - Evaluate the feasibility of fuel cells (natural gas inventory part of EE benchmarking)
    - Determine deal and contracting strategy (e.g. lease versus buy)
    - Issue a RFP to solicit PV and Fuel Cells developers on select buildings
  - Conduct outreach to residential and business community to encourage the use of existing renewable energy programs
  - Consider "stretch" building codes to promote Zero Energy construction

EVERSOURCE ENERGY

Appendix

Distributed Generation in Greenwich

EVERSOURCE ENERGY

- YTD June 2016 – there are 15 new customers connected – nameplate total of 0.12 MW (120 kW)
- YTD June 2016 – there are 24 new customer requests – nameplate total of 0.282 MW (282 kW)
- Experience has shown that many requests are never completed or completed late and the actual generation outputs are less than request
- The DEEP Microgrid and Clean Energy RFPs have yielded zero customers in Greenwich

Distributed Generation - Fuel Cell Opportunity

EVERSOURCE ENERGY

- The first large commercial fuel cell – nameplate rating of 0.525 MW was interconnected in 2015
- Bloom Energy has approached Eversource to assist in the development of a targeted fuel cell program in Greenwich
- Bloom has provided customer criteria to Eversource – see below:

Bloom Customer Criteria - Greenwich

1. 250kW+ of 24x7 minimum baseload electricity behind a single meter
2. Creditworthy customer, typically BB rated or higher (Alternatively, Eversource could consider providing a credit enhancement product to non-creditworthy customers)
3. At least 650ft^2 space outdoors or on a rooftop with freight elevator access within 500ft of the customer's main electrical switchgear

Bloomenergy

Brooklyn Queens Demand Management Program

EVERSOURCE ENERGY

Source: BQDM QUARTERLY EXPENDITURES & PROGRAM REPORT, Q-1 2016, Consolidation Edison of New York Inc., May 31, 2016

	Design Stage*	Deployment Stage*
Customer-side Solutions		
Small Business Direct Install		√
Multi-family Energy Efficiency		√
Residential Energy Efficiency Program(s)	√	
Bring Your Own Thermostat Adder ("BYOT")	√	
Virtual Building Audits		√
New York City Housing Authority		√
Direct Customer Activity		√
Dynamic Resource Auction**	√	
Fuel Cells		√
Queens Resiliency Microgrid	NP	NP
City Agency Solutions	√	
Commercial Refrigeration	√	
Combined Heat and Power ("CHP")		√
Battery Storage		√
Utility-side Solutions		
Distributed Energy Storage System		√
Distributed Generation (DC-Link)	√	
Voltage Optimization		√
Utility Side PV Pilot	√	
Fuel Cell	√	
Foundational Elements		
Distributed Energy Resource Evaluation Tool		√
Solutions Technology Validation		√
Community Engagement and Outreach		√
Auction Designs and Analyses		√
Measurement & Verification Pilot		√
Demand Management Tracking System		√

Table 2: BQDM Program Activity

Brooklyn Queens Demand Management Program

EVERSOURCE ENERGY

- New York PSC approval for $200M program to defer the need for a new substation
  - December 12, 2014 program established
- Active Programs in Deployment Stage
  - Customer-side Solutions
    - Small Business Direct Install – 4155 small businesses for 6.88 MW at peak hour
    - Multi-Family Energy Efficiency – 1002 multi-family buildings (7681 apartments) for 3.62 MW at peak hour
    - Fuel Cells – multiple locations identified
    - Combined Heat and Power (CHP)
    - Battery Storage
  - Non-traditional utility-sided solutions
    - Distributed Energy Storage System – 2 MW for up to 6 hours
    - Voltage Optimization – 4 MW

Fuel Cell Installation - Industrial Scale

EVERSOURCE ENERGY

- Fuel Cell Characteristics:
  - Requires of 3 to 5 acres of land
  - Requires a high pressure gas line
  - Requires the inflow of 60,000 gallons of water per day
  - Expels 30,000 gallons of waste water per day

Pictured Above: Dominion Bridgeport Fuel Cell

ATTACHMENT E

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.

Table of Contents

Acknowledgements

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This report benefitted from the contributions of the many professionals who are designing, implementing, testing, and regulating the use of energy efficiency and other non-wires approaches as alternatives to traditional T&D construction. We especially thank the following for giving us their assistance:

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- Lindsay Foley, National Grid;
- Michael Harrington, Con Ed;
- Richard Aslin, PG&E;
- Bill Kallock, Tom Osterhus and Scott Smith, Integral Analytics;
- Rob Ozar, Michigan Public Service Commission;
- T.J. Poor, Vermont Public Service Department;
- Gillian Eaton, Efficiency Vermont;
- Chuck Cohen & colleagues, Maine Public Utilities Commission;
- Beth Nagusky, formerly Environment Northeast;
- Dan Blais, GridSolar;
- Ian Barnes, Efficiency Maine;
- Jeff Schlegel, Schlegel & Associates;
- Marco Padula, NY Public Service Commission;
- Nita Zimmerman and colleagues, Bonneville Power Administration
- Eric Winkler, ISO New England
- Sharon Daly, MA Department of Public Utilities

The generous contributions of time and knowledge from those listed above made the report possible, but any fault for errors or mischaracterizations that it may contain lies with the authors alone.

[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.

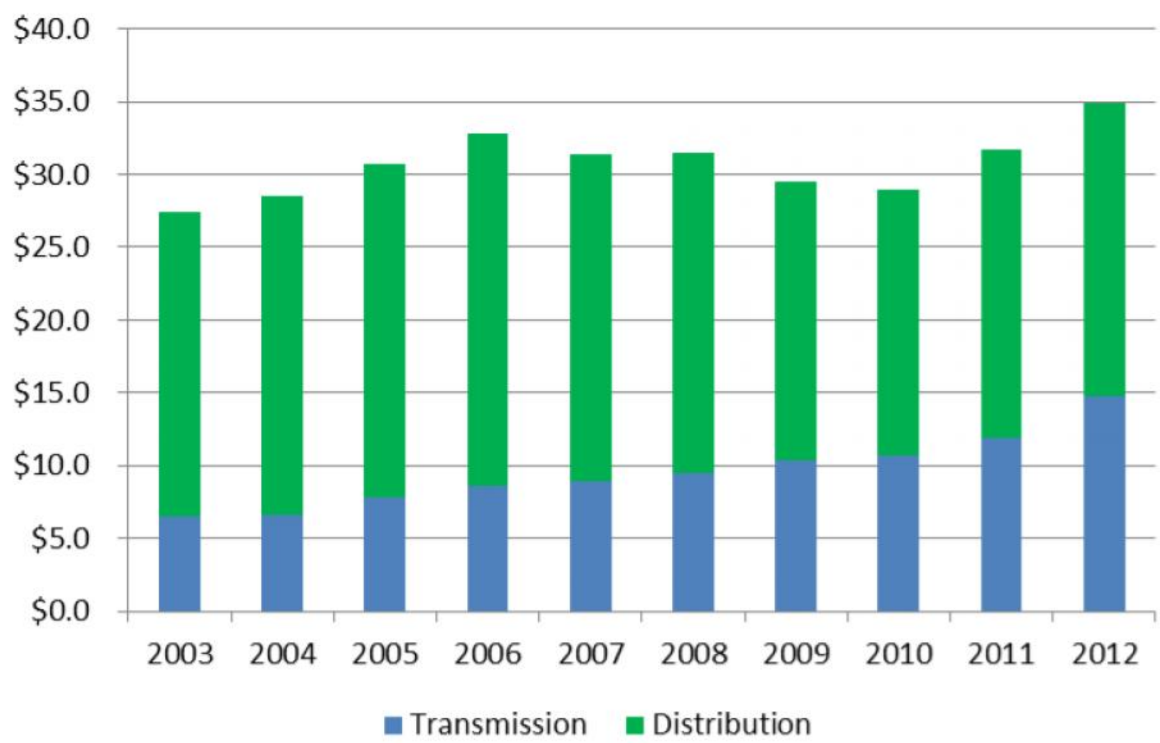
Appendices – contain excerpts from legislation in Vermont, Maine and California; regulatory standards for Rhode Island; and screening forms for Vermont that underpin those states' current requirements to consider and, where appropriate, promote non-wires alternatives.

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.

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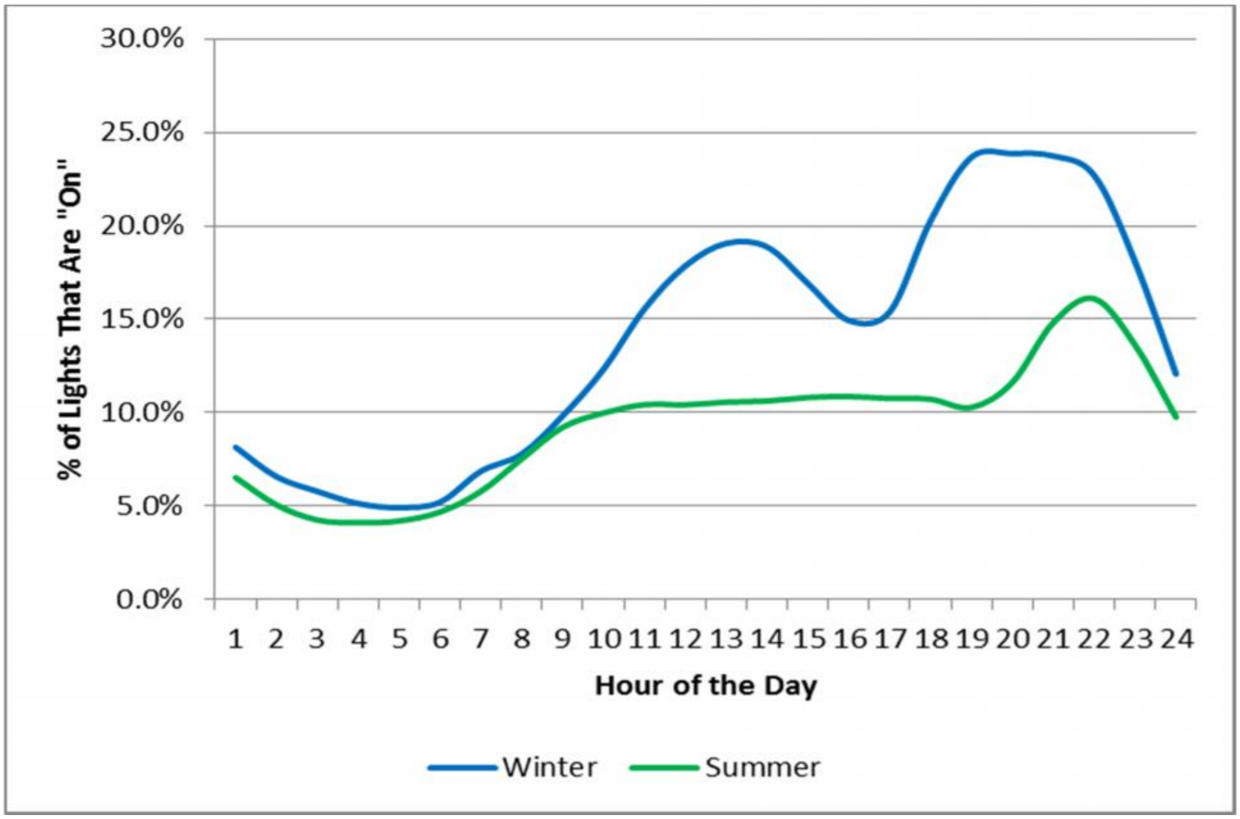
[9] Harris Williams & Co., *Transmission and Distribution Infrastructure*, a Harris Williams & Co. White Paper, Summer 2014 (http://www.harriswilliams.com/sites/default/files/industry_reports/ep_td_white_paper_06_10_14_final.pdf?cm_mid=3575875&cm_crmid=e5418e44-29ef-e211-9e7f-00505695730e&cm_medium=email).

[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]

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[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

[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

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[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-

[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.

[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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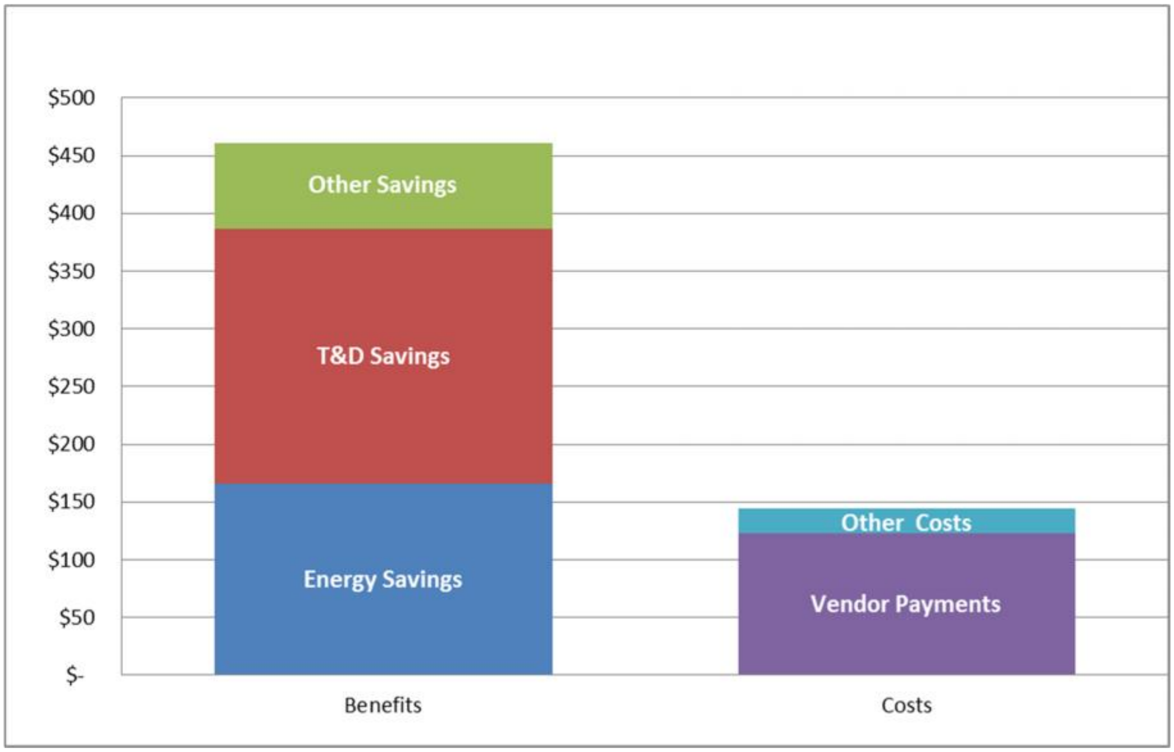
[47] Data obtained from graph in Gazze, Mysholowsky, Craft and Appelbaum (2010).
[48] Gazze, Mysholowsky, Craft and Appelbaum (2010).
[49] Gazze, Mysholowsky, Craft and Appelbaum (2010).
[50] Gazze, Chris et al., "Con Ed's Targeted Demand Side Management Program: Replacing Distribution Infrastructure 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]

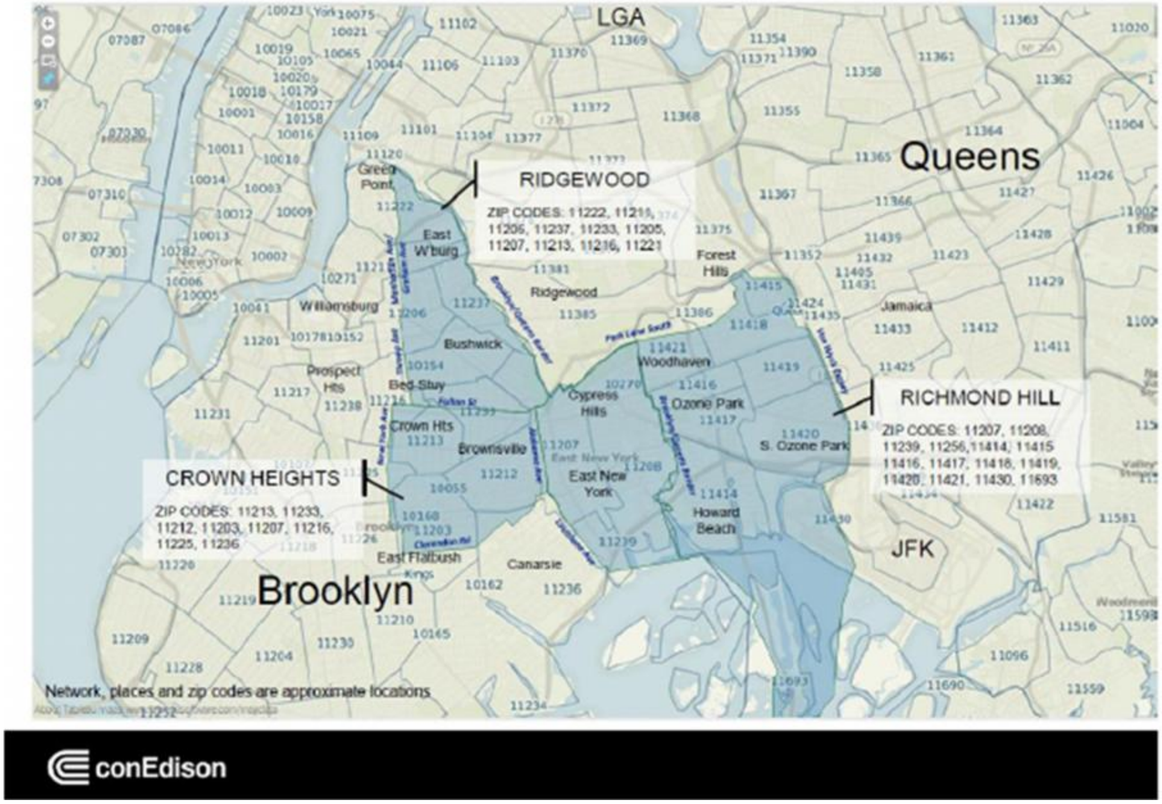


The Next Big Step - $200 Million Brooklyn-Queens Project

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).

[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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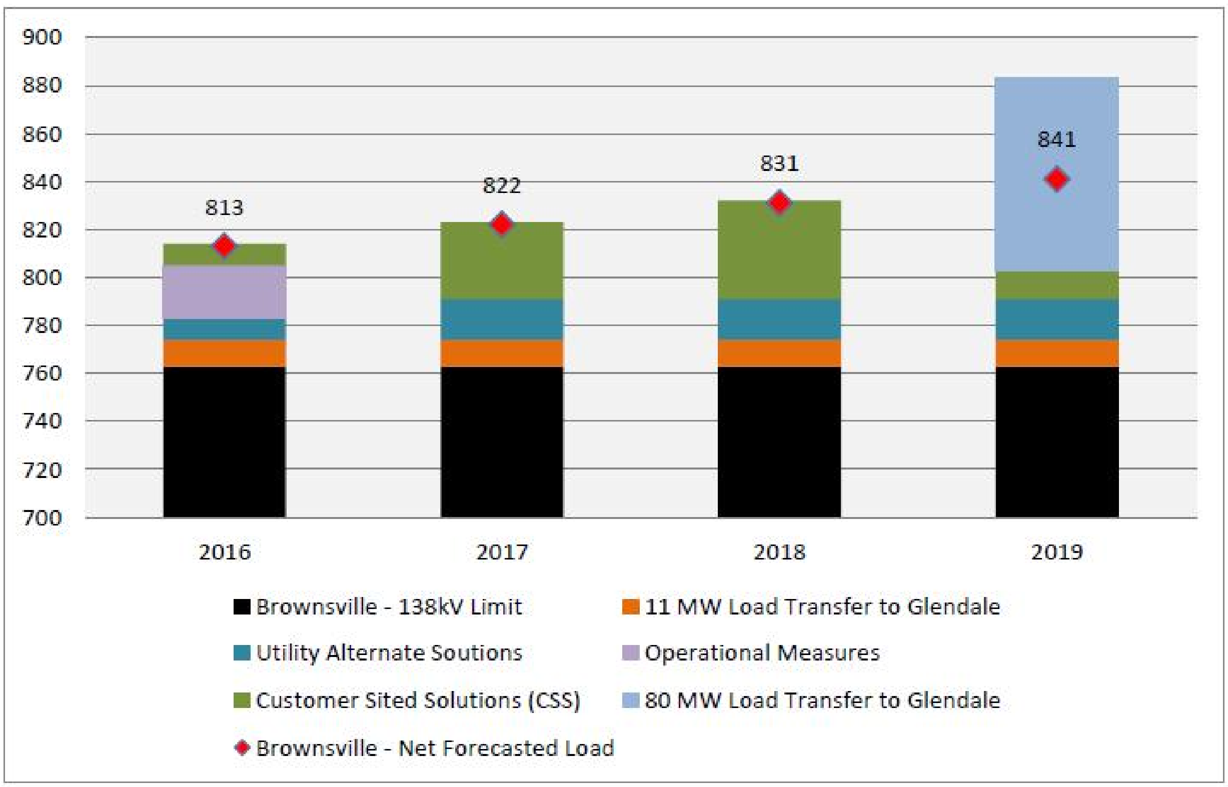
[52] Consolidated Edison Company of New York Request for Information, July 15, 2014, p.11.
[53] Personal communication with Michael Harrington of Con Ed, July 24, 2014.
[54] Data regarding Con Ed's proposal are from Consolidated Edison Company of New York, Inc. Brownsville Load Area Plan, Case 13-E-0030, 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

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[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

[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

[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

[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.

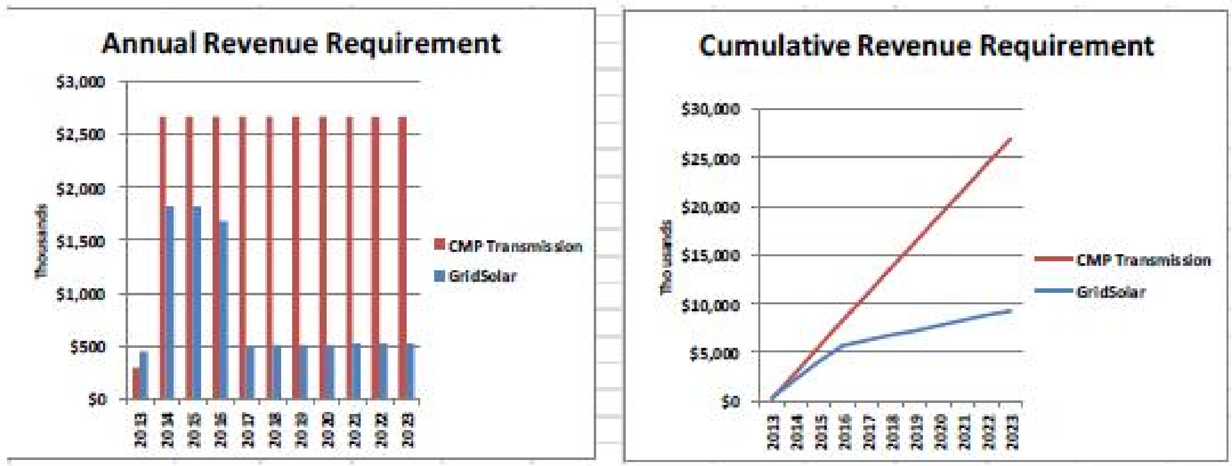
Project Results

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.

[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]

[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

[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

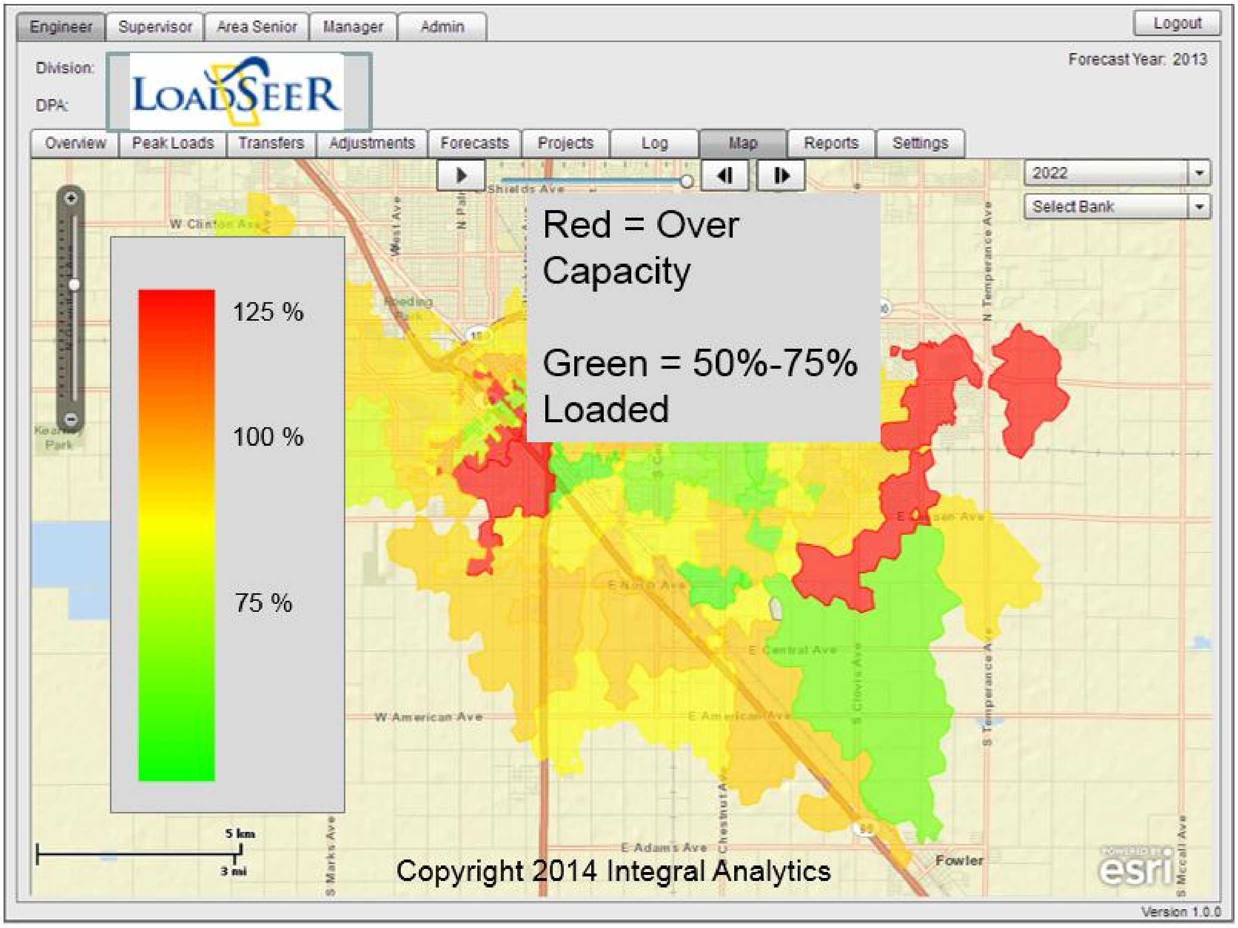
PG&E, like other utilities in this study, has identified challenges working across traditional utility organizational structures that typically have system planners operating in isolation from demand management and energy efficiency staff. PG&E, as well as other utilities with whom we talked, has found 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]

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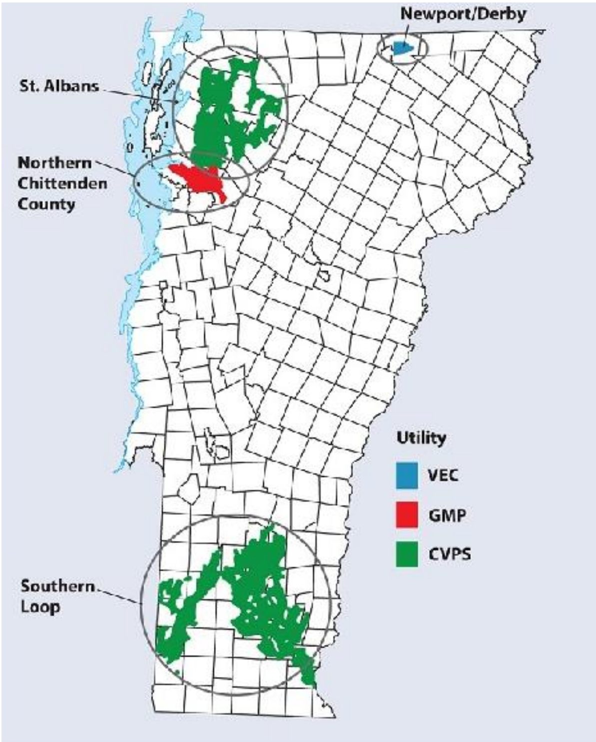
[96] Vermont Public Service Board, *Order Re: Energy Efficiency Utility Budget for Calendar Years 2006, 2007 and 2008*, 8/2/2006.
[97] Efficiency Vermont Annual Plan, 2008-2009.

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]

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[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.

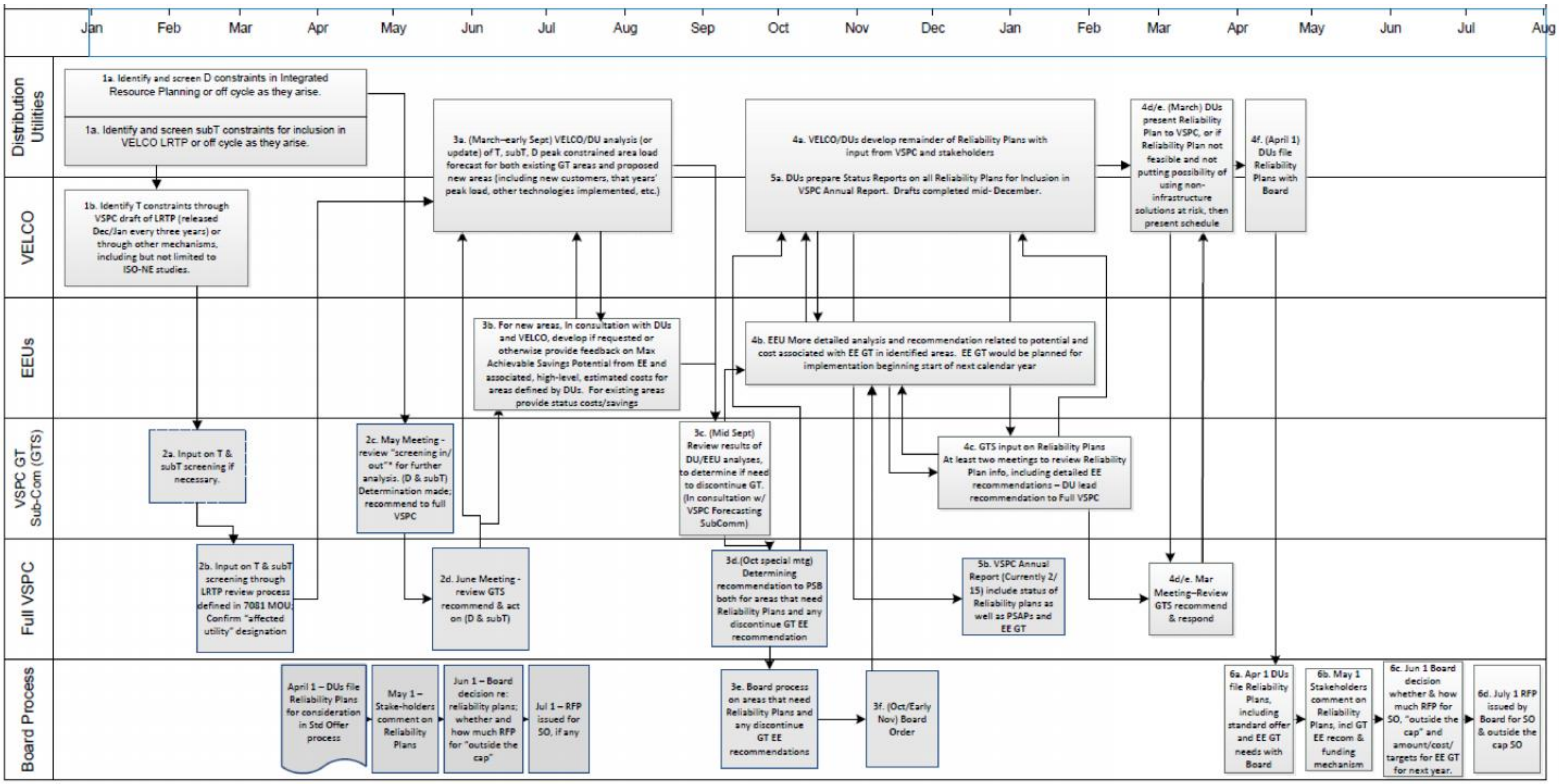
The VSPC process overcomes two significant barriers by first making sure that potential system constraints are identified as far in advance of their needed construction dates as possible, and secondly by ensuring that efficiency program planners are brought into the conversation early enough to determine 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
DU	distribution utility
EE	energy efficiency
EEU	energy efficiency utility
GT	geographic targeting
GTS	VSPC Geotargeting Subcommittee
LRTP	VELCO Long-Range Transmission Plan
PSAP	project-specific action plan
RFP	request for proposal
SO	standard offer
subT	subtransmission (subsystem)
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 4 to 5 6 to 10	15% 20% 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.

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.)* *If "no," project screens out of full NTA analysis.*	❑ Yes ❑ 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.)* *If "no," project screens out of full NTA analysis.*	❑ Yes ❑ 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.)* *If so, check "Yes" and continue to Line 4; otherwise check "No" and. continue to Line* 2	Yes .☐ No ..☐
2.	Would the upgrade relieve a T&D delivery constraint in a Capacity Constrained Area? *(See note.)* *If so, check "Yes" and continue to Line* 3*; otherwise check "No" and* exclude *the expected upgrade from DU analysis.*	Yes .☐ No ..☐
3.	Is the cost of the upgrade less than $250,000? *(See note.)* *If so, check "Yes" and* exclude *the expected upgrade from DU analysis; otherwise check "No" and continue to Line 4.*	Yes .☐ 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? *If so, check "Yes" and* exclude *the upgrade from DU analysis; otherwise check "No" and continue to line 5.*	Yes .☐ No ..☐
5.	Does the upgrade constitute a minor change for the purpose of system tuning or efficiency improvements? *(See note.)* *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 .☐ 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 replacement of wires on such equipment with the least-cost wires. *(See note.)*..	☐
5.j	• Other (please describe): ________________________________ ________________________________ ________________________________ ________________ (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? *If so, check "Yes" and* exclude *the upgrade from DU analysis; otherwise check "No" and continue to line 7.*	Yes .☐ 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.)* *If so, check "Yes," describe the situation,* ________________ ________________________________ ________________________________ ________________________________ *and* exclude *the expected upgrade from DU analysis; otherwise check "No" and continue to line 8.*	Yes .☐ No ..☐
8.	Is the upgrade required to remedy reliability, stability, or safety problems?	Yes .☐ 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.)* *If so, check "Yes" and continue to line 10; otherwise check "No" and skip to line 11.*	Yes .☐ No ..☐
10.	Is the likely reduction in costs from the potential reduction in scope less than $250,000? *(See note.)* *If so, check "Yes" and* exclude *the upgrade from DU analysis; otherwise check "No" and continue to line 11.*	Yes .☐ 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.).* *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 .☐ 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? *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 .☐ 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. 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: • Replacement of large transformers • 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.

ATTACHMENT F

A summary of some of VEIC's experience analyzing and deploying location-specific distributed energy resources

August 21, 2018

Who are VEIC, Efficiency Vermont, and Green Mountain Power (GMP)?

VEIC is a nonprofit organization with a mission to act with urgency to enhance the economic, environmental, and societal benefits of clean and efficient energy use for all people. Since its founding in 1986, VEIC's staff have designed, implemented, or evaluated energy efficiency, smart grid, or renewable energy policies and programs in more than 37 states, six Canadian provinces, and seven countries in Europe and Asia.

Efficiency Vermont is the statewide energy efficiency utility in Vermont[1] operated by VEIC. Through an order of appointment with the Department of Public Service, Efficiency Vermont provides energy efficiency services across the state to customers of co-operative and municipal utilities, and Vermont's single investor owned utility, Green Mountain Power. Efficiency Vermont has been achieving annual savings near 2% of electricity sales for several years. The peak capacity savings Efficiency Vermont provides are bid into ISO-New England's Forward Capacity Market as the largest capacity resource in Vermont, over 100 MW of peak savings compared to a statewide peak demand near 1,000 MW.

Green Mountain Power (GMP) has a vision to use energy as a force for good that improves lives and transforms communities. GMP is focused on a new way of doing business to meet the needs of customers with integrated energy services that help people use less energy and save money, while continuing to generate clean, cost effective and reliable power in Vermont. GMP's innovative programs include offering leases for heat pumps, incentives for electric vehicles, and upfront discounts on Tesla Powerwalls. Green Mountain Power is not affiliated with this document or filing, but this introduction is here because they contracted with VEIC for the analyses below. GMP serves about three quarters of Vermont's electricity demand.

Location specific efficiency analysis

VEIC has completed two studies for Green Mountain Power to determine whether energy efficiency could avoid or defer the need to upgrade or build a substation. One substation had a thermal problem due to longer times of high load, whereas the other was more a concern of a short term peak. Part of the analysis is talking with the distribution engineers to understand their concerns.

In Rutland, GMP provided the accounts for 32,000 premises served by a substation and asked if efficiency could provide at least 4.2 MW of peak reduction in an area defined as core (with a 67 MW peak), or at least 8.4 MW in a wider area (with a 96 MW peak) in three years. VEIC estimated 5.4 MW of peak savings were available in the core area at a cost of $15M-$20M and recommended targeted efficiency programs be deployed there with incentives covering 80-100% of incremental measure cost. The wider area would have offered more potential customers and had higher total potential, but would not have been able to reach the target under the time constraint.

---

[1] Burlington's municipal utility was already achieving strong results when Efficiency Vermont was created so it was allowed to continue. Burlington Electric and Efficiency Vermont collaborate and offer very similar incentives and programs.

The Rutland core area had already been the target of geographically targeted peak reduction efficiency efforts. VEIC considered those existing savings when estimating the remaining potential. Compared to Rutland, Greenwich's higher air conditioning use increases the opportunity for efficiency and demand response.

In Hinesburg, GMP asked VEIC how much efficiency could contribute to an efficiency plus storage alternative to a new substation. In this case, the area of interest was just one feeder with 2,300 customers, 2,000 of whom were residential. Feeder load data showed greatly increased variability due to a new large solar system. There was a 5.6 MW winter peak and 4.9 MW fall peak in the most recent grid data. A GMP engineer provided a hand drawn graph of efficiency savings versus cost and asked to see that as a result of this study. While VEIC provided that graph for the feeder in question, initial analysis showed that in this case, in two years, efficiency would not be able to save enough to relieve pressure on the substation. Therefore, VEIC did not complete the full analysis and provided the initial estimate to GMP sooner than expected and at lower cost.

Usage and efficiency program participation data were available for both of these projects and were used in Rutland. However, a higher level approach was used in Hinesburg, and VEIC would similarly adapt our methods to the timeline and data availability in Greenwich. To the extent it is available, VEIC can use data on energy consumption by sector, and efficiency program participation, and can estimate savings by sector and end use.

In both GMP projects, there was enough solar on the circuits that the afternoon net load was lowered and the new peak appeared after sunset. Green Mountain Power has solar capacity equivalent to 20% of their peak demand. In California, solar provides so much energy the daily load curve is entirely different. Rather than a two hump daytime demand above lower nighttime demand, there is a gradual ramp from pre-dawn until the 6pm peak. On a recent sunny spring day when VEIC was visiting the CAISO control room, solar was providing about two thirds of the region's electricity that afternoon. Solar's contribution depends on the timing and shape of the peak and the amount of solar already installed, but it sounds like there is plenty of opportunity for solar to help more in Greenwich.

Storage, in water heaters, ice, and batteries offers significant opportunities. VEIC is estimating the potential of the strategies in RAP's *Teaching the Duck to Fly* paper in Vermont for a study about getting 20% of the state's annual electricity from solar by 2025, which would require 1,000 MW of solar on a grid that peaks at that level. The potential for efficiency, solar, storage, and demand response all depend on location and the problem they are trying to address. Greenwich's mix of commercial and residential buildings and affluence are likely to mean the potential for these strategies is relatively high.

Geo-targeted efficiency resource acquisition

Vermont has included non-wires alternatives in least cost planning for many years and Efficiency Vermont has actually delivered targeted programs to constrained areas. A Navigant evaluation[2] of the geo-targeting efforts includes the table below, which shows peak reduction compared to area peak load.

[2]Navigant Consulting et al., "Process and Impact Evaluation of Efficiency Vermont's 2007-2009 Geo-targeting Program," 2011.
http://publicservice.vermont.gov/sites/dps/files/documents/Energy_Efficiency/EVT_Performance_Eval/Navigant_Vermont%20GeoTargeting%202010%20Process%20%20Impact%20Evaluation%20FINAL%20.pdf

On average, Efficiency Vermont achieved 4% demand savings in one three-year performance cycle, for participants beyond nonparticipants. Evaluated results can give greater confidence in what efficiency can deliver, and can be a source for estimates of the depth and speed efficiency can be deployed. More recent verified performance data is available, though it has not been the subject of another full evaluation.

Table 55. GT Verified MW Reduction and Utility 2007 MW Peak

Region	2007 Peak MW	Total Net Peak MW Reduction Achieved (2007 - 2009)[36]	MW Reduction as % of 2007 Peak MW
North Chittenden	64	4.30	6.7%
St. Albans	78	3.07	3.9%
Southern Loop	70	3.15	4.5%
Newport	18	0.69	3.8%

VEIC continues to implement cost effective demand management programs that could be implemented for large, targeted savings in the affected areas. Variable frequency drives and ice storage for HVAC, and server-related demand response technologies each provide cost-effective demand reduction during summer peak times without affecting customer operations. These programs can be implemented very quickly and could serve immediate needs in the Greenwich area.

Rhode Island's System Reliability Procurement Program and Tiverton/Little Compton Pilot

In 2006 the Rhode Island Legislature passed a bill mandating the public utilities commission follow principles of least cost procurement when directing the utility to procure energy, energy efficiency, and system reliability as it relates to the electric system. Under this law, National Grid conducts system reliability procurement (SRP) that evaluates wires and non-wires alternatives (NWA) when considering upgrades to the distribution grid. As consultant to the Energy Efficiency and Resource Management Council which oversees National Grid's efficiency and SRP programs, VEIC reviews and provides guidance on SRP plans, reports, and implementation efforts. The Tiverton/Little Compton (TLC) project is an SRP pilot that may be of particular relevance to Greenwich. TLC was designed by National Grid to test whether geographically-targeted energy efficiency and demand response could defer the need for a new substation feeder to serve 5,200 customers (80 percent 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). 2017 is the final year of the Pilot's planned lifecycle and approximately 330kW are needed to reach the goal of 1MW by the end of the year. To reach this goal, the utility will continue geo-targeting marketing and incentives for Wi-Fi thermostats, heat pump water heaters, window AC purchases, and recycling. This program has also include pilots related to time-of-use rates that may be a useful tool in addressing the concerns in Greenwich.[3]

---

[3] Northeast Energy Efficiency Partnerships, "A Look Inside the Region's Latest Non-wires Alternative Projects and Policies," 2016.
http://www.neep.org/blog/look-inside-region%E2%80%99s-latest-non-wires-alternative-projects-and-policies

ATTACHMENT G

Session: Enabling Technologies for Energy Resiliency

Energy Exchange
Federal Sustainability for the Next Decade
U.S. Department of Energy

Parkville MicroGrid

Antonio J. Matta
Hartford, CT
August 11, 2016

Parkville MicroGrid

Concept

- Hartford, CT has major power interruptions caused by storms resulting in loss of community services even with emergency generators
- Parkville cluster provides essential community services in one on-site and two off-site locations
- Services include: school, library, senior center, health center, grocery store and gasoline station

Goal

Create a stand-alone MicroGrid that will link all services and through a fuel cell power source provide all of their electrical needs

Parkville MicroGrid

Interconnected Facilities – on site

School

Library

Senior Center

Health Center

Parkville MicroGrid

Interconnected Facilities – off site

Grocery Store

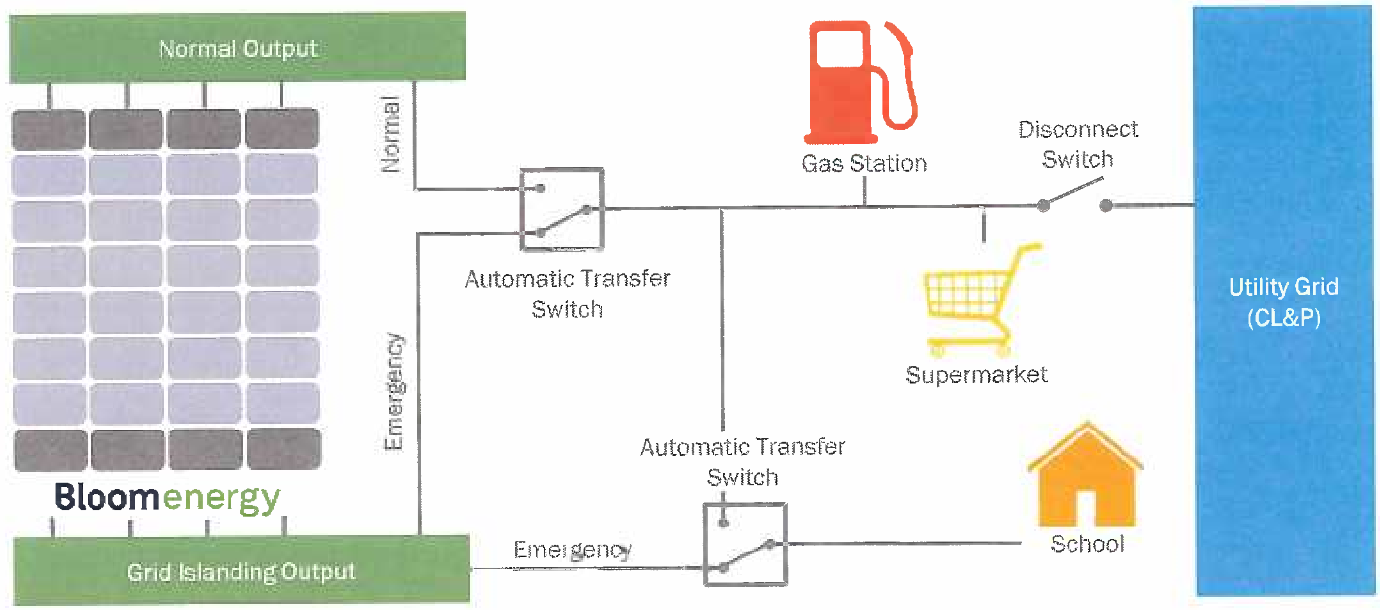
Gasoline Station

Parkville MicroGrid

Site Plan

Parkville MicroGrid

Project Overview



Context	▪ City of Hartford looking for a resilient power solution to serve critical community facilities that could act as a refuge for residents during emergencies or bad weather
Results	▪ City of Hartford project consists of 800 kW baseload power with 640 kW of grid islanding capability to provide a community MicroGrid.
Customer Value	▪ Constellation and Bloom Energy were able to provide a PPA to the City of Hartford that had significant cost savings, avoided upfront capital for passive backup equipment, and met sustainability objectives through Bloom's energy solution

Parkville MicroGrid

The "Players"

- City of Hartford, Department of Public Works – *customer*
- Weston and Sampson – *customer's energy consultant*
- Bloom Energy – *fuel cell design and construction*
- Constellation – *overall design and project management, fuel cell and MicroGrid site design / interconnect and construction / system owner*
- GI Energy / Van Zelm Engineers / Environmental Systems Design – *Constellation's consultants*
- Eversource – *MicroGrid design, construction and operation*
- Connecticut Natural Gas – *design and construction of high pressure gas line*

- Community
  - *Parkville School*
  - *Senior Center*
  - *Library*
- Regulatory Committees
  - *Parkville Neighborhood Revitalization Zone*
  - *Planning and Zoning*
  - *Zoning Board of Appeals*
  - *CT Siting Council*

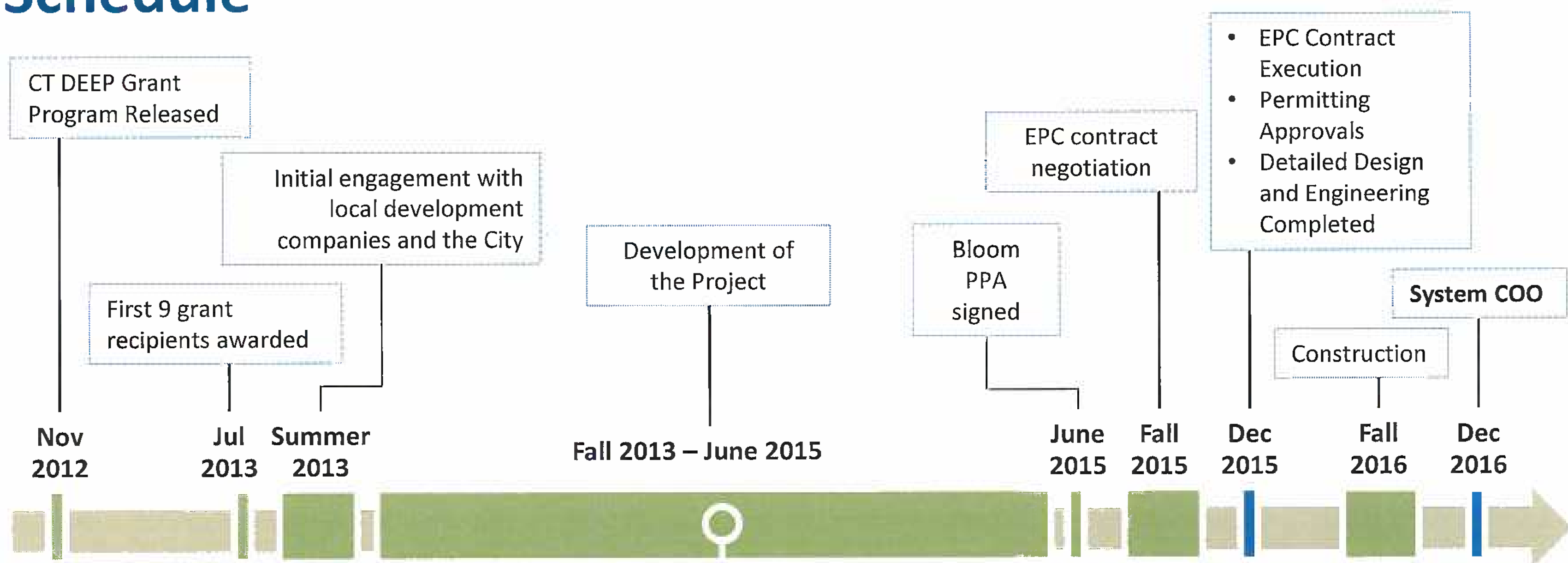
Parkville MicroGrid

Financial Components

- DEEP MicroGrid Grant - $2,063,000
- City Financing (Municipal Bonds) - $1,300,000
- Financial Incentives
  - Low Emission Renewable Energy Credits (LRECs)
  - Virtual Net Metering (VNM)
- Overall energy savings over current utility rates (projected) - $500,000

Parkville MicroGrid

Schedule



Key Development Activities

- **Selection of generator technology**: Initially CHP but lack of onsite heat load led to use of a Bloom fuel cell
- **CT LREC bid submission and award:** Bidding strategy required to ensure you are "picked up" while protecting project economics
- **Virtual Net Metering:** Site load under normal conditions @ 20% of fuel cell output required a structure to export excess energy that is only used by the MicroGrid during grid outages
- **Securing Eversource engagement and sign-off**: New model for all parties requiring a collaborative effort
- **Ensure adequate pipeline gas pressure:** Dedicated high pressure gas line for Bloom fuel cell provides extra reliability but greater upfront cost

Parkville MicroGrid

Challenges and Results

Challenges

- Economically viable (at or below current cost of electricity)
  - LREC (Low Renewable Energy Credit) help to solve this problem along with VNM (Virtual Net Metering)
  - DEEP Grant
- Technology selection: Very little thermal load resulted in switch from a traditional engine to a Bloom fuel cell
- Technical hurdles – Gas pressure, Bloom MicroGrid, spare UPM, VNM
- Many players involved – City, Eversource, CNG, Constellation, Bloom, Bloom/Constellation
- Coordination and ability to migrate through varied complexities

Results

- A MicroGrid system that will help manage electricity costs and supply emergency power to a portion of the city's Parkville neighborhood
- Connecticut's first MicroGrid to be developed thorough a public-private effort
- One of the first MicroGrids to be developed under Connecticut's Department of Energy & Environmental Protection (DEEP) MicroGrid Grant Program
- **Proof that utilities, project developers, manufacturers, state and local government, and project owners CAN work together to make MicroGrids happen …**

Parkville MicroGrid

Construction Photographs

Site clearing

Underground Utilities

Fuel Cell

Operational

- Contact Information
  - Antonio J. Matta
  - City Architect
  - Hartford, CT
  - tmatta@hartford.gov
  - (860) 757-9982

ATTACHMENT H

Town of Greenwich

Clean Energy and Climate Change Timeline

2007 through 2017

The Town of Greenwich, with the Conservation Commission as the lead department, has been working on Clean Energy strategically since 2007.

- 2007 – Town Conservation Staff participates in Climate Change Summit for municipalities held by CT DEEP.
- 2008 - The Town of Greenwich formalized its commitment to clean energy and energy conservation when the Board of Selectman voted to become a Clean Energy Community. Launches outreach /education with town wide Energy Fair. Energy Management Team put in place to look at both Town energy and also community outreach led by Conservation Commission. Town energy resolution also adopted by Board of Selectman.
- 2008 – ongoing Conservation begins educational campaign on sea level rise and coastal hazards using GIS mapping including providing mapping for exhibit on climate change at the Bruce Museum
- 2008 - Energy management and climate change adaptation issues were both introduced into the 2008 POCD as action items for the first time.
- 2009 – 2013 - Conservation Director Denise Savageau, served on the Adaptation Subcommittee of the Governor's Steering Committee on Climate Change Adaptation Subcommittee where she co-chaired the workgroup on Infrastructure. The Adaptation Subcommittee produced Connecticut's Climate Change Preparedness Plan in 2011 which was released in 2013.
- 2009 – Conservation Commission applies for $680,000 grant for Glenville School solar array that is installed as part of the school renovation. This resulted in 95 kW system installed.
- 2010 – Greenwich reaches Clean Energy Community goals and is awarded installation of 7.10 kW system at GHS.
- 2011 – Town hires intern and begins benchmarking energy usage in all municipal buildings. Board of Education leads the way with comprehensive benchmarking and energy conservation strategy. Town fleet adds hybrid vehicles and continues addressing energy conservation in facilities.
- 2013 – Town renews its Clean Energy Community pledge and continues it's work with the CT Clean Energy Fund on both energy efficiency and alternative energy
- 2013 -2014 – Town adopts C-PACE for commercial properties to help fund and launches outreach program. Town also participates CT Solarize program for residential property

owners. 41 new solar installations are completed doubling the number of solar installations in Town in just 12 months.

- 2014 – Climate change adaptation introduced into the Town Hazard Mitigation Plan
- 2015 – Town begins updating of benchmarking and progress on clean energy goals over the next fiscal year.
- 2015 – Town awarded two "Bright Idea Grants" from the CT Green Bank for its progress as part of the Clean Energy Program
- 2016 – Town engages with Eversource and the CT Energize Program. Following the Siting Council decision on the proposed substation, Town and Eversource work on solutions. Town adopts Energy Plan outline proposed by Eversource for energy efficiency but expands to include exploring modernizing the grid and alternative energy based on CT Energize workshops attended by Conservation members and staff. Works with Eversource to finish updating benchmark. Launches HES program.
- 2017 – completes bench marking and identifies Town Hall for initial audit. Audit completed Feb 2017. Based on 2016 successes, began discussion with Eversource about ramping up the program. Eversource proposes develop a strategic plan followed by an MOU for implementation. As of August 2017, a JT committee with Eversource and Town staff is in place for the strategic planning with a planning date set for Sept 27, 2017. Simultaneously, Town re-engages with CT Green Bank to discuss alternative energy and modernization of grid.

ATTACHMENT I

Compilation of documents relating to Town of Greenwich energy efficiency efforts

TABLE OF CONTENTS

16. Letter from First Selectman to residents relating to Town of Greenwich Home Energy Solutions program, October 12, 2016

17. Press Release relating to Town of Greenwich Light Bulb Swap, November 23, 2016

18. Flyer for Town of Greenwich Light Bulb Swap on April 22, 2017

ATTACHMENT I-1

CLEAN ENERGY RESOLUTION
adopted by the
Board of Selectmen
Town of Greenwich, Connecticut
March 27, 2008

Supporting the Goal of 20% Clean Energy by the Year 2010

WHEREAS, the Town of Greenwich seeks to take measures to improve air quality standards because of its importance to public health; and

WHEREAS, clean energy resources, such as wind and solar energy, constantly replenishing themselves, do not cause the buildup of global warming gases and health damaging pollutants, and, if properly managed, will be available to serve our energy needs forever; and

WHEREAS, the economic impact of not using conservation technology and alternative energy sources results in direct and indirect costs to Greenwich citizens. These costs include environmental, medical, and lost days at work; and

WHEREAS, the 20% by 2010 campaign is a Connecticut not-for-profit initiative being undertaken to encourage community action in support of clean energy in an effort to improve public health, create a clean energy market, improve the environment and create jobs in these technologies; and

WHEREAS, the Town of Greenwich Board of Selectmen has endorsed the goals of the 20% by 2010 Campaign;

NOW, THEREFORE, BE IT RESOLVED that the Town of Greenwich commit to offsetting at least 20% of its electricity usage with clean energy sources by the year 2010, with clean energy purchases increasing over time to meet the 2010 goal; and

BE IT FURTHER RESOLVED that the Town of Greenwich shall achieve this goal by, at a minimum, purchasing enough clean energy certificates to account for 20% of its power consumption; and

BE IT FURTHER RESOLVED that the Town of Greenwich Board of Selectmen create a clean energy task force, under the direction of the Conservation Commission, that will research and make recommendations so that Greenwich can reach the 20% by 2010 goal. The Task Force will investigate clean energy options; including purchasing Renewable Energy Certificates (RECs) and/or on-site renewable energy installations and funding opportunities; and

BE IT FURTHER RESOLVED that the Board of Selectmen encourages all businesses, institutions and households within Greenwich to adopt the goal of making at least 20% of their energy purchases come from renewable energy sources by the year 2010.

ATTACHMENT I-2

GREENWICH CLEAN ENERGY FORUM

SPONSORED BY THE TOWN OF GREENWICH & THE BRUCE MUSEUM

TOWN OF GREENWICH CONN. SEAL

BRUCE MUSEUM

JUNE 3, 2008 (TUES) 7-9 PM

AT THE BRUCE MUSEUM

1 MUSEUM DRIVE, GREENWICH, CT

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TOWN OF GREENWICH ENVIRONMENTAL UPDATE

- CT CLEAN ENERGY COMMUNITY PROGRAM by Bob Wall
- SOLAR ENERGY OPTIONS by Jared Haines, Mercury Solar Systems
- ENVIRONMENTAL ACTION TASK FORCE, by Lin Lavery, Selectman
- 350.ORG (STEP IT UP GOES GLOBAL) by Will Bates, 350.org

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GO TO: WWW.CTCLEANENERGYOPTIONS.COM
FOR PROGRAM DETAILS & SIGN UP TODAY

FOR EVERY 100 GREENWICH RESIDENTS WHO ENROLL IN THE PROGRAM, THE TOWN OF GREENWICH IS ELIGIBLE TO RECEIVE A FREE 1 KILOWATT PHOTOVOLTAIC (PV) SOLAR ENERGY SYSTEM ($10,000 VALUE) FROM THE CT CLEAN ENERGY FUND.

CLEAN ENERGY. LET'S MAKE MORE.

ATTACHMENT I-3

Town of Greenwich Board of Selectmen's
Environmental Action Task Force Energy Policy Resolution
Adopted by the Board of Selectman
August 14, 2008

WHEREAS, the Town of Greenwich aspires to lead among municipalities and, by example, its Citizens in improving energy management policies; and

WHEREAS, the Town aspires to reduce the adverse impact of rising energy costs on the Operating Budget; and

WHEREAS, the Town aspires to reduce the carbon dioxide (CO_2) load on the environment due to the Town's use of fossil energy.

NOW THEREFORE BE IT RESOLVED that the First Selectman appoint an Energy Management Team to improve the Town's energy management by identifying ways to improve energy usage, continuously monitoring performance, and recognizing achievement, and be it

FURTHER RESOLVED that the Town establish its energy use in a baseline year and set targets for reducing energy use, energy costs, and $C0_2$ emissions, and be it

FURTHER RESOLVED that the Town evaluate its operations to identify unnecessary energy consuming activities and eliminate these; and be it

FURTHER RESOLVED that the Town identify the most economical and environmentally efficient available technologies to conduct its operations, develop implementation plans and budgets, and incorporate these plans into department operating plans and in the Town's Annual Budget; and be it

FURTHER RESOLVED that the Town incorporate total life cycle costs into purchasing and capital acquisition decisions that consider fuel costs, $C0_2$ emissions and ongoing maintenance costs in addition to initial purchase price; and be it

FURTHER RESOLVED that the Town make use of grants, incentives, and rebates that may be available when energy efficient technologies are utilized.

August 14, 2008

ATTACHMENT I-4

renewable choice
ENERGY

Purchase Agreement

Terms: Annual - Net 30

Date: December 18, 2009

PA Exp. Date: January 3, 2010

Client Name: Town of Greenwich
Contact Name: Joan Sullivan
Contact Email: jsullivan@greenwichct.org
Shipping Address: 101 Field Point Rd.
Greenwich, CT 06830
Phone: (203) 622-7884
Fax:
Marketing Contact:
Email Address:

Billing Company: Town of Greenwich
Contact Name: Joan Sullivan
Contact Email: jsullivan@greenwichct.org
Billing Address: 101 Field Point Rd.
Greenwich, CT 06830
Phone: (203) 622-7884
Fax: 203-622-7776

[illegible]	[illegible]	Quantity (kWh)	Price ($/kWh)	Amount	
100% based on electricity use for Year 1	Green e® Certified Clean Source	3,100,000	$0.00139	$4,309.00	☒
100% based on electricity use for Year 2	Green e® Certified Clean Source	4,500,000	$0.00139	$6,255.00	☒
100% based on electricity use for Year 3	Green-e® Certified Clean Source	4,500,000	$0.00139	$6,255.00	☒
			Total	$16,819.00	

Limited Representations and Warranties of RCE. RCE represents and warrants to Client that the Products retired under this Agreement (i) have not been sold, transferred, contracted for or otherwise committed to any third party, or otherwise used or claimed by RCE or, to the best knowledge of RCE, any third party and (ii) have been independently certified. EXCEPT AS SPECIFICALLY SET FORTH HEREIN, THE PRODUCTS ARE SOLD "AS IS", AND RCE SPECIFICALLY DISCLAIMS ANY AND ALL OTHER REPRESENTATIONS AND WARRANTIES, EXPRESS OR IMPLIED, STATUTORY OR OTHERWISE, INCLUDING WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE.
Retirement. Client shall not resell or otherwise transfer the Products. Products (or any portion thereof) are considered retired when RCE removes them from inventory.
Limitation on Liability. In no event shall either RCE or Client be liable to the other or to any third party under or in connection with this Agreement for any special, indirect, incidental, punitive, consequential or similar damages, including, without limitation, any damages resulting from lost profits.

The undersigned agrees that he is authorized to engage in an agreement on behalf of the company below. By signing, the company agrees to the purchase amount and terms outlined on this page.

JOAN T. SULLIVAN
Joan T. Sullivan 12/29/09
TOWN OF GREENWICH, CT DIRECTOR OF PURCHASING

Order Acceptance: The undersigned agrees that he is authorized to and has accepted this order and the ~~tariffs~~ outlined on this page on behalf of Renewable Choice Energy.

12/29/2009

Aran Rice – Vice President of Sales – Renewable Choice Energy

Product Content Label

This is a renewable certificate product. For every unit of renewable electricity generated, an equivalent amount of renewable certificates is produced. The purchase of renewable certificates supports renewable electricity generation, which can help offset conventional electricity generation in the region where the renewable generator is located. You will continue to receive a separate electricity bill from your utility. This product matches up to 100% of your estimated electricity usage. The product will be made of any or all of the new renewable resources listed below and updated annually.

Clean Source™ contains some or all of the following New** Renewable Resources	Generation Location
Wind, Biomass, Small Hydro and Geothermal	Nationwide

** Includes renewable generators that first started operating after January 1, 1997 or as regionally defined

For comparison, the current average mix of energy sources supplying the U.S. includes: Coal (50%), Nuclear (20%), Natural Gas (18%), Large Hydro-electric (7%), Oil (3%), and Renewables (2%) (data from USEPA E-GRID)

For specific information about this product, contact Renewable Choice Energy at 877-810-8670 or on the web at www.renewablechoice.com

Green-e® Energy certifies that Clean Source™ meets the minimum environmental and consumer protection standards established by the non-profit Center for Resource Solutions. For more information on Green-e Energy certification requirements, call 1-888-63-GREEN or log on to www.green-e.org.

Green-e Energy Certified

Questions or comments? Contact us.
Representative: John Powers
Fax: 270.916.3551

ATTACHMENT I-5

U.S. Department of Energy

ENERGY EFFICIENCY AND CONSERVATION BLOCK GRANT (EECBG)
DRAFT PROGRAM PERFORMANCE REPORT

***** THIS REPORT CONTAINS RECORDS THAT HAVE NOT YET BEEN APPROVED BY DOE *****

Grant Number: SC0001493 Final Report: ☐ Grantee: Town of Greenwich

Activity: Glenville School Photovoltaic System
Quarter: 07/01/2010 - 09/30/2010 Metric Activity: Renewable Energy Market Development
Status: Active % of Work Complete: 100

Activity Description:

The Town of Greenwich is proposing to implement an on-site renewable technology installation on a public school building. Specifically, as part of a new school construction project, a photovoltaic (PV) solar system will be installed on the roof of Glenville School. Preliminary design estimates that using new technology, the roof could accommodate a large system of at least 100kW and generate about 15% of the electricity needs for the school building. The Glenville School is being replaced by a brand new structure and is in mid-construction. It is slated for completion in December 2009. The school was designed to include a PV system on the roof. Budget constraints originally forced the town to reconsider installing the PV system, however, the decision was made to include the wiring and infrastructure needed for a PV system so as not to preclude adding them in the future. The roof of the building is complete and includes the appropriate wiring/infrastructure. The ECCBG will allow the Town to move forward with the installation of a roof-top PV system as originally planned. Because the Town's school building committee planned ahead, the installation is a stand alone project and not tied to other aspects of the construction. Ideally, the Town would like to begin installation of the PV system in September 2009 and have it on line for the school opening in early December 2009. However, again because this is a stand alone project, the installation could be delayed until the summer of 2010 if EECBG funds where not available until then.The Town is currently reviewing PV options that would work with our roof design, including a "thin film" system and a stand alone frame system that sits on top of the PVC roof. The Town is leaning towards the stand alone frame design as it allows of roof repair without impacting the PV system. However, no final will be made until funding is awarded and final bids are received.Budget: Total for engineering and installation of 100kW system - $995,000.00. EECBG funding 627,500. Town funding $331,500.00. State reimbursement $ 36,000. All administrative costs will be in-kind service by the Town.*GHG Emissions (C02 equivalents)is using a kWh conversion factor of .537 = kg of CO2

Key Dates:

DESCRIPTION	START DATE	COMPLETION DATE
Activity Planned	10/01/2009	01/22/2010
Activity Actual	10/01/2009	04/30/2010

MILESTONES

Activity Milestone Status:

MILESTONE	PLANNED AMOUNT	TOTALS TO DATE	% OF PLAN	PLANNED START	ACTUAL START	ACTUAL COMPLETION	STATUS	07/01/2010-09/30/2010			
Installation of 100 kW PV system on Glenville School.	995,000	0	0%	10/01/2009	10/01/2009	04/30/2010	Delayed	0			

INFRASTRUCTURE INVESTMENT

Infrastructure Investment:

U.S. Department of Energy

ENERGY EFFICIENCY AND CONSERVATION BLOCK GRANT (EECBG)
DRAFT PROGRAM PERFORMANCE REPORT

*** THIS REPORT CONTAINS RECORDS THAT HAVE NOT YET BEEN APPROVED BY DOE ***

Grant Number: SC0001493 Final Report: ☐ Grantee: Town of Greenwich

Activity: Glenville School Photovoltaic System - continued -
Quarter: 07/01/2010 - 09/30/2010
Status: Active

Metric Activity: Renewable Energy Market Development
% of Work Complete: 100

Does this activity contain an infrastructure investment? Yes
Rationale for Funding the Infrastructure Insvestment:

Installing 100 kW Solyndra Photovoltaic system on Glenville School.

QUALITATIVE DESCRIPTIONS

Reporting Period: 07/01/2010- 09/30/2010

Are you following the Plan? If not, describe the change in approach, and reasons for the change.
Yes - plan was followed
Major Activities, Significant Results, Major Findings, and Key Outcomes
Installation of 97.5kW Solyndra PV system completed and opertational
What we planned to accomplish this period
Project completed in this quarter. No grant activity to follow. Will continue to monitor PV system to determine actual output and % of electric usage at the school. Estimates for the system are between 12 and 15% of total school electric needs. Initial assesment is that this is on target.

95 kW system installed at Glenville School, Greenwich CT – 2009-10

ATTACHMENT I-6

TOWN OF
GREENWICH

Office of First Selectman (203) 622-7710 Fax (203) 622-3793
Town Hall • 101 Field Point Road • Greenwich, CT 06830
E-Mail: ptesei@greenwichct.org

Peter J. Tesei
First Selectman

January 13, 2010

Mr. H. Curtis Spalding
Regional Administrator
EPA New England
5 Post Office Square – Suite 100
Boston, MA 02109-3912

Dear Mr. Spalding:

With this letter, Town of Greenwich, Connecticut joins EPA New England's Community Energy Challenge and commits to becoming an EPA Energy STAR partner. We are making a commitment to protect the environment through the continuous improvement of our energy performance. We believe that an energy management strategy for our municipal buildings and facilities will help us enhance our financial health and aid in preserving the environment for future generations. In partnership with EPA, we will specifically:

- **Asses – benchmark – the energy performance of all municipal buildings, schools and/or drinking water/ wastewater treatment facilities in our community**

- **Set a goal to reduce energy use in buildings by 10% or more**

- **Promote energy efficiency and renewables to companies and organizations in our community**

We understand that our commitment to assess and improve the energy performance of our community is supported by the strategic resources and tools offered through the Community Energy Challenge. In addition, we are aware that both ENERGY STAR and the Community Energy Challenge present opportunities to be recognized for success. To be eligible for recognition, we will share with EPA our progress and milestone achievemenets.

The Town of Greenwich looks forward to our partnership with EPA.

Sincerely,

Peter J. Tesei
First Selectman

Enclosures

ATTACHMENT I-7

Expression of Interest Form to Participate in
Municipal Climate Intern Program
Spring Semester 2011

Please check boxes and complete the following. Then email this completed form to lynn.stoddard@ct.gov before 5:00 p.m. on January 10, 2011. Thank you for your interest.

☑ My town has completed the municipal climate change survey at http://www.surveymonkey.com/ctclimate

☑ My town is willing and able to provide a supervisor and work space for the intern.

☑ My town is willing and able to identify a climate change project(s) for the intern.

☑ My town is willing and able to support the intern in developing a work plan and implementing the project(s).

My town would like an intern to work on one or more of the following climate change projects (list briefly). The projects may address climate change mitigation and/or adaptation. You may list one or more projects.

1. Energy benchmarking & audits of town buildings
2. Energy symposium (April 2nd, 2011)
3.
4.

☑ I understand that funding is limited and that my town may not be selected to receive an intern under this program for the spring 2011 semester.

☑ I am a town employee or elected official.

Name: Denise Savageau

Title: Conservation Director

Town: Greenwich

Date: Jan. 4, 2011

ATTACHMENT I-8

ENERGY CONSCIOUS HOME

Less Cost & More Comfort

Saturday, April 2

Greenwich High School

10 am - 3 pm

Environmental innovation has always been strong in Greenwich. Now, with a focus on 23,230+ households, the Town of Greenwich's Conservation Commission is launching a new era of cost & energy efficient action with the Energy Conscious Home Forum.

This open forum will feature exhibits & presentations on energy conservation topics including:

- Local Green & Healthy Home Examples
- Solar Hot Water & Electricity Choices
- Efficient Lighting & Home Appliances
- Where To Start & Costs for Conservation
- Cost-saving Rebate Programs
- Renewable Energy Supplier Choices
- Air Sealing, Insulation & Heat Loss Audits
- Rain Garden & Sustainable Landscaping

OPEN TO THE PUBLIC ~ CHECK FOR PRESENTATION TIMES ONLINE
RSVPs & DONATIONS APPRECIATED. SIGN-UP ONLINE.

WWW.GREENGREENWICH.COM

info@greengreenwich.com / Jeff Cordulack: 203-869-5272 x239

Committee Co-Chairs: Jessica Brockington & Meg McAuley Kaicher
Steering Committee: Susie Baker, Nancy Chapin, Jeff Cordulack, Jeanine Getz, Gina Gould, Gayle Hagegard, Denise Savageau
Program Committee: Kristine D'Elisa, Steve Hall, Foster Lyons

TOWN OF GREENWICH CONN. SEAL

GREEN GREENWICH

GARDEN EDUCATION CENTER GREENWICH

Audubon AT HOME

Ella Vickers
Recycled Sailcloth Collection

CONNECTICUT DEPARTMENT ENVIRONMENTAL PROTECTION

Thank You To Our Sponsors

COASTAL POINT CONSTRUCTION

GA GRANOFF ARCHITECTS

2011

ATTACHMENT I-9

CLEAN ENERGY COMMUNITIES MUNICIPAL PLEDGE

The Clean Energy Communities program is an initiative funded by both the Clean Energy Finance and Investment Authority (CEFIA-formerly known as the Connecticut Clean Energy Fund) and the Connecticut Energy Efficiency Fund. CEFIA and the Energy Efficiency Fund develop programs which collectively seek to have Connecticut cities and towns both reduce energy use and increase support for clean, renewable energy for municipal facilities. The Energy Efficiency Fund programs are administered by The Connecticut Light and Power Company, The United Illuminating Company, Yankee Gas Services Company, The Southern Connecticut Gas Company, and/or Connecticut Natural Gas Corporation (collectively, "the Companies")

By applying currently available energy efficiency and clean, renewable energy technologies the Town of Greenwich can save money, create a healthier environment and strengthen local economies; and **accordingly, the Town of Greenwich makes the following Clean Energy Communities Municipal Pledge:**

1. The Town of Greenwich pledges to reduce its municipal building energy consumption by 20% by 2018. Building energy consumption shall be determined by benchmarking municipal building energy consumption to a baseline fiscal year. The Town of **Greenwich** can elect from the following fiscal years to determine its energy baseline year: 2008-2009, 2009-2010, 2010-2011, or 2011-2012.

a. The Town of Greenwich will seek to reduce its municipal building energy consumption for municipal facilities by at least 20% by 2018. The schedule follows:

i. Fiscal Year 2012-2013: 5% Reduction
ii. Fiscal Year 2013-2014: 8% Reduction
iii. Fiscal Year 2014-2015: 11% Reduction
iv. Fiscal Year 2015-2016: 14% Reduction
v. Fiscal Year 2016-2017: 17% Reduction
vi. Fiscal Year 2017-2018: 20% Reduction

b. The Town of Greenwich will work with "the Companies", contractors or other entities to benchmark all of its municipal buildings (including board of education buildings) to determine all municipal building energy usage.

c. Beginning July 1, 2015, the Town of Greenwich agrees to provide documentation of its municipal building energy consumption on an annual basis by the end of the first quarter of the following fiscal year.

d. The Town of Greenwich pledges to create its own Municipal Action Plan (MAP) to determine its path in reducing its energy consumption. The Town of Greenwich may satisfy this requirement by submitting a pre-existing municipal energy plan, sustainability plan, climate change action plan or similar document. This may modify the schedule shown in 1a but with a final goal of 20% by Fiscal Year 2017-2018.

e. There is no penalty if the Town of Greenwich fails to meet the reduction amounts set forth in the schedule above. However if these reduction targets are not met starting July 1, 2015, the Town of Greenwich will not be eligible to receive Bright Ideas Grants from the Connecticut Energy Efficiency Fund and Companies under the Clean Energy Communities program.

2. The Town of Greenwich pledges to purchase 20% of its municipal building electricity from clean, renewable energy sources by 2018.

a. The Town of Greenwich will seek to make a voluntary purchase of at least 20% of the electricity for municipal facilities from clean, renewable energy sources by annual CEC program requirements. The schedule follows:

ii. Fiscal Year 2013-2014: 16% Purchase

iii. Fiscal Year 2014-2015: 17% Purchase

iv. Fiscal Year 2015-2016: 18% Purchase

v. Fiscal Year 2016-2017: 19% Purchase

vi. Fiscal Year 2017-2018: 20% Purchase

b. The Town of Greenwich agrees to provide CEFIA documentation of its municipal clean energy purchases on an annual basis by the end of the first quarter of the following fiscal year. CEFIA intends to request documentation of municipal clean energy purchases for FY2011-2012 in July 2012.

c. The Town of Greenwich acknowledges that clean, renewable sources are those defined in section 16-1 of the general statutes as Connecticut Class I renewable energy sources or meeting Green-e® Energy certification standards.

d. The Town of Greenwich may satisfy the voluntary purchase requirement by purchasing Green-e® Energy certified Renewable Energy Credits (RECs), enrolling one of more municipal facilities in the CTCleanEnergyOptions^{sm} program, installing renewable energy systems (provided that the RECs associated with such system(s) are quantifiable and not held by a third-party) or any combination thereof.

e. There is no penalty if the Town of Greenwich fails to meet the items set forth in the schedule above; however, the Town of Greenwich will not be eligible to receive incentive rewards from CEFIA under the Clean Energy Communities program.

3. The Town of Greenwich agrees to promote energy efficiency and clean, renewable technologies in its community. The Town of Greenwich is encouraged to establish a Clean Energy Task Force, or comparable body. This entity will assist the municipality in meeting the Clean Energy Communities Municipal Pledge and to perform education and outreach among residents, businesses and institutions within the community concerning energy efficiency and clean, renewable energy programs.

By taking the pledge and meeting the Clean Energy Community Program requirements outlined by CEFIA and the Connecticut Energy Efficiency Fund, the Town of Greenwich may qualify, subject to the terms of separate formal contracts, for the following grants:

a. CEFIA. For every 100 points, the Town of Greenwich may earn a 1 kilowatt (or equivalent) clean energy system.
b. Energy Efficiency Fund. For every 100 points, the Town of Greenwich may earn a Bright Idea Grant that can be used for energy-saving projects. The Town of Greenwich is eligible for two Bright Idea Grants per fiscal year.

Peter J. Tesei, First Selectman

Peter J. Tesei

Signature

Town of Greenwich, Connecticut

* The Town of Greenwich understands that the Clean Energy Communities Municipal Pledge is not a contract, and that CEFIA, the Energy Efficiency Fund, and the Companies have not contracted, committed, agreed or promised, to perform or incur any obligations, in any manner, hereunder.

ATTACHMENT I-10

Greenwich Renews its Commitment as a Connecticut Clean Energy Community (2013 Press)

Question 1: What is the Clean Energy Communities Program and how is Greenwich involved?

Answer 1: The Clean Energy Communities program was developed by the CT Clean Energy Fund (now Clean Energy Finance and Investment Authority or CEFIA) to encourage Towns to support the use of clean energy with a goal of improving air quality and reducing greenhouse gas emissions. This program is for the community at large, not just Town owned facilities. Greenwich became involved with the Clean Energy Community program following a resolution passed by the Board of Selectmen in March 2008. The Conservation Commission coordinated the program and Greenwich succeeded in reaching its goal in January 2010 resulting in the Town receiving a free photovoltaic solar system for Greenwich High School. The 7.7 kilowatt (kW) solar system was installed on the science building at GHS in November 2011.

In 2012, CEFIA formally partnered with the Connecticut Energy Efficiency Fund (CEEF) for a joint program with two focus areas: energy conservation and alternative energy. Greenwich renewed its commitment to the program in July 2013. As a result, the town can earn more rewards in the form of "Bright Idea Grants" from CEEF and clean energy systems from CEFIA. The rewards are based upon participation by local residents and businesses in CEEF and CEFIA programs such as Home Energy Solutions, Residential Solar Investment Program or C-PACE. The Conservation Commission is taking the lead, working with CEFIA, to engage the community in programs such as the Solarize Greenwich for residential property owners and C-PACE for commercial property owners.

Question 2: What is Solarize Greenwich?

Answer 2: Earlier this summer, the Conservation Commission applied for Greenwich to be part of the Solarize Connecticut program. This program uses the power of group purchasing to provide greatly discounted photovoltaic solar installations to residents of participating communities. On September 4, 2013, CEFIA announced that Greenwich had been selected for the program and that, as decided by CEFIA and the Town, Renewable Resources Energy Solutions of Stamford, CT would be our pre-selected, competitively chosen installer. The Commission is very excited about Solarize Greenwich and providing the opportunity to reduce electricity bills to our residential building owners.

We are in the process of putting together a team of solar ambassadors to help us get the word out about the program. The installation prices are tiered so the more installations in Greenwich, the better the discount. This discount program will run for 20 weeks from our kickoff event scheduled for October 2, 2013 at 7 p.m. in the Town Hall meeting room. We will be promoting this at various events throughout September leading to the kickoff event. Each installed system will also earn 3 points for the town under the Clean Energy Communities program. Similarly, each application for a CEFIA financing product such as CT Solar Lease, CT Solar Loan and Smart-E Loan will earn an additional point for the town. For more information on Solarize Greenwich go to the website at http://solarizect.com/our-towns/greenwich/.

Question 3: What is a solar ambassador?

Answer 3: The Commission is looking for residents who are interested in helping promote clean energy in Town by becoming solar ambassadors for the Solarize Greenwich program. This team of volunteers will work with the Conservation Commission, CEFIA, and Renewable Resources on our marketing campaign by distributing posters and flyers, working at events, or telling us about your solar installation. If you are interested in helping with this please contact Denise Savageau at denise.savageau@greenwichct.org.

Question 4: What is C-PACE?

Answer 4: Earlier this year, the Board of Selectman and then the RTM voted for Greenwich to become a C-PACE community. Commercial & Industrial Property Assessed Clean Energy better known as C-PACE is an innovative financing model that allows building owners to access cleaner, cheaper, and more reliable energy. Basically, it allows owners to make clean energy improvements to their property and pay for it over time similar to a sewer easement assessment. The assessment stays with the property. Because the payment is tied to the property, low interest capital can be raised from the private sector for things such as energy efficient boilers, new windows, or solar installations.

Most commercial buildings need some type of energy upgrade that can result in significant savings on energy costs. Each completed C-PACE project will earn 20 points for the town and each application for C-PACE financing will earn an additional 5 points under the Clean Energy Communities program.

Question 5: What is considered a commercial building for C-PACE?

Answer 5: All non-residential buildings, or residential with 5 or more dwelling units are considered commercial for C-PACE purposes. This includes buildings owned by religious institutions and non-governmental organizations. Even if you are tax-exempt, you are eligible to use this program.

Question 6: What is the Town doing to reduce energy use on Town facilities?

Answer 6: Key departments have been working on energy conservation and clean energy for some time and staff now meets regularly, as part of an energy team, to discuss energy opportunities and solutions. Besides the solar installation at GHS, a 95 kW system was installed on Glenville School as part of a Clean Energy Block Grant. Our Dept. of Public Works is slowing upgrading all lighting and has installed small solar systems as appropriate throughout town including at Great Captain's Island. The Sewer Division is currently conducting an energy audit and the Parking Division is looking at a pilot installation of a charging station for electric vehicles. Earlier this year several town officials including staff from Board of Education and Conservation and BET member, attended a program on performance contracting. Energy conservation and alternative energy solutions are becoming part of standard operating procedures for most departments. I expect that an even greater emphasis will be put on this now that we understand that clean energy can result in significant savings.

ATTACHMENT I-11

Solarize Greenwich!

TOWN OF GREENWICH CONN. SEAL

Solar. Simple. Together.

renewable resources
Inspiring energy solutions

Come to a Solarize Workshop!

November 6 Wednesday

Eastern Greenwich Civic Center
90 Harding Road
Old Greenwich, CT
7:00 – 8:30 pm

November 21 Thursday

Cone Room, Town Hall
101 Field Point Road
Greenwich, CT
11:30 am – 1:00 pm

December 4 Wednesday

Audubon Greenwich
613 Riversville Road
Greenwich, CT
7:00 – 8:30 pm

Come learn about this limited-time collaboration of the Town of Greenwich, Renewable Resources and CEFIA to make solar energy an easy and economical choice for our residents.

- *Discount pricing*
- *Pre-selected installer*
- *No-money-down financing*

Solarize CONNECTICUT℠
GREENWICH

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www.SolarizeCT.com/Greenwich

energize CONNECTICUT CT℠

ATTACHMENT I-12

Solarize CONNECTICUT℠ GREENWICH

For Immediate Release

Contact: Denise Savageau
Conservation Director, Town of Greenwich
203 622-6461
Denise.Savageau@greenwichct.org

Solarize Greenwich More than Doubles Solar in Greenwich

Greenwich, CT —Solarize Greenwich, a town and state sponsored program designed to dramatically increase residential solar, reached the end of its 20-week program on February 18, 2014. Over the course of the program, Solarize Greenwich helped 48 residents go solar, generating 280kW of power and more than doubling the number of solar installations in Greenwich.

The Clean Energy Finance and Investment Authority (CEFIA), The John Merck Fund, and SmartPower partnered with Greenwich to develop Solarize Connecticut. Solarize leverages community outreach and the power of group purchasing to encourage residential solar installations.

Renewable Resources, Inc., Solarize Greenwich's chosen installer, offered discounted pricing in return for support from the town. The more homeowners who participated in Solarize Greenwich, the lower the price dropped for all Greenwich homeowners.

"I've always wanted to go solar… so when I heard about the Solarize Greenwich program, I jumped right on it," reported Greenwich resident Joan Franzino, "My quote from Renewable Resources was so good, down about 35%, that I signed up immediately. The construction went by in FLASH- believe me, I've had lots of construction done, and these guys were light speed. I saved money the first day they flipped the switch!"

Greenwich First Selectman Peter Tesei was equally pleased with the program's results. "As a Clean Energy Community, we're extremely proud of what we have been able to achieve through the Solarize program. We are excited that so many of our residents responded to this opportunity to lower their energy bills by going solar. Many thanks to our volunteers and Renewable Resources, Inc. who worked so hard to make these results possible."

While Solarize Greenwich is formally closed, those who are interested in solar may still contact Renewable Resources, Inc. at 203-204-6891 to learn if discounts are still being offered to residents.

For more information on Solarize Connecticut please contact SmartPower Outreach Manager Kate Donnelly at kdonnelly@smartpower.org or 860-604-4846.

###

ATTACHMENT I-13

energize CT
CONNECTICUT

Empowering you to make
smart energy choices

C-PACE: A Clean Energy Opportunity for Commercial Buildings in Greenwich

First Selectman's C-PACE Reception and Panel Presentation

September 19, 2013
5:30 to 8:00 p.m.
Town Hall Meeting Room
101 Field Point Road, Greenwich, CT 06830

Agenda

5:30 to 6:15p.m.
Reception with light refreshments

6:15 – 6:25 p.m.
Welcome and Opening Remarks – Peter J. Tesei, First Selectman
Brief Overview of Clean Energy in Greenwich – Denise Savageau, Conservation Director

6:25 – 7:45 p.m.
Panel Presentations with Q&A
Moderated by JoAnn Messina, League of Women Voters Past President

C-PACE Overview – Genevieve R. Sherman, CEFIA
Energy Design – "Finding the Gold in Your Building" – Steve Hall, Chandler llc
Financing C-PACE – Bert Hunter, Chief Investment Officer, CEFIA
C-PACE Case Study – Bob Hartt, Hartt Realty Advisors, LLC
Q&A

7:45 – 8:00 p.m.
Final Wrap up and Networking

This evening is sponsored by the Town of Greenwich Conservation Commission in coordination with the Connecticut Clean Energy Finance and Investment Authority (CEFIA)
RSVP @ 203-622-6461

ATTACHMENT I-14

Clean Energy Communities Rewards (Archived)
Bob Wall to: denise.savageau@greenwichct.org 08/03/2015 02:50 PM

Follow Up:	Normal Priority.
History:	This message has been forwarded.

Click here to open full message

Message Summary:

Dear Clean Energy Leader,

Congratulations! Thanks to your leadership, the Town of Greenwich has earned 2 rewards from the Connecticut Green Bank (CGB) through the Clean Energy Communities program.

As a participant in the Communities program, your town receives points and earns rewards when local residents and businesses participate in programs such as Home Energy Solutions, Residential Solar Investment Program and Commercial Property Assessed Clean Energy (C-PACE). The CGB, formerly the Clean Energy Finance and Investment Authority, provides rewards earned on the "Renewable Energy track" of the program. This is in addition to the "Bright Idea Grants" towns earn for every 100 points on the "Energy Efficiency track". Each reward is currently worth $4,500 and may be used for any project involving energy efficiency, renewable energy or alternative fuel vehicles. Although solar PV systems have been a popular reward, towns have branched out recently by applying their reward towards an electric vehicle charging station (Fairfield), a solar-powered trash compactor (Essex), and a geothermal system (Middletown). In order to help with your decision, we refer you to the Reward Guide copied below. We encourage creativity in selecting an energy-related project that is important to your community's goals.

ATTACHMENT I-15

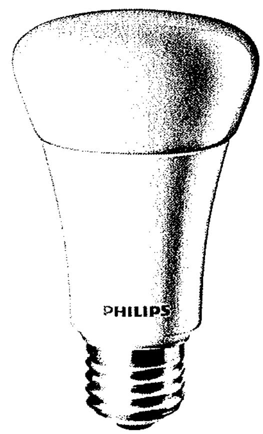
energize CONNECTICUT CT℠

Empowering you to make smart energy choices

GREENWICH LIGHT BULB SWAP

Swap up to 5 incandescent light bulbs for 5 free LED light bulbs

OCTOBER 25, 2016
5 PM – 8 PM
Greenwich Town Hall
Meeting Room
101 Field Point Road



Bring your old light bulbs and proof of Greenwich residence (photo ID or your Eversource electric bill) to receive up to 5 free long-lasting, energy-saving LED light bulbs. No purchase is necessary, but for each additional light bulb purchased, Energize Connecticut will donate a bulb to Habitat for Humanity.

877-WISE-USE
EnergizeCT.com

ENERGY STAR

EVERSOURCE ENERGY

Energize Connecticut programs paid for by a charge on customer energy bills.

ATTACHMENT I-16

Town of Greenwich
Office of the First Selectman (203) 622-7710 • Fax (203) 622-3793
Town Hall – 101 Field Point Road – Greenwich, CT 06830
Email: peter.tesei@greenwichct.org

October 12, 2016

Dear Greenwich resident,

As a clean energy community, the town of Greenwich has partnered with Eversource to save you money and lower your energy bills. We would like to offer you Home Energy Solutions℠, an Energize Connecticut℠ program. A certified and insured contractor will visit your home to evaluate your energy use and make on-the-spot improvements.

During the visit, the technicians provide services and install products valued at an average of $1,000 per household:

- Long-lasting, energy-saving LED and CFL light bulbs
- Devices to reduce your hot water use
- Air sealing to reduce drafts and keep conditioned air in your home
- Safety tests on your heating equipment to ensure they are working properly
- A report on your energy usage and recommended ways you can save more
- Rebates, incentives, and financing options to make additional improvements more affordable

After the visit, most customers save about $200 every year on their energy bills. All this for one, low fee!*

Participating in Home Energy Solutions this calendar year also benefits our community – it makes us eligible for grants to pursue energy-saving projects. Plus, for every Home Energy Solutions visit, our partner-contractors, CT Weatherproof Insulation, New England Smart Energy Group, and New England Total Energy, will make a $25 donation to Greenwich Tree Conservancy.

Call 877-WISE-USE or visit EnergizeCT.com/HES to learn more and sign up.

Join us on October 25th, ENERGY STAR Day, for a Light Bulb Swap
5:00 PM - 8:00 PM
Town Hall Meeting Room, Greenwich Town Hall
101 Field Point Rd
Swap up to 5 old incandescent light bulbs and receive up to 5 new LEDs per household.
You must bring your light bulbs and proof of Greenwich residence in order to receive the 5 LED bulbs.
Bulbs are 60-watt equivalent only and are available while supplies last.

Thank you for making Greenwich a cleaner community.

Yours truly,

Peter J. Tesei

Peter J. Tesei, First Selectman

* Home Energy Solutions is available to all Eversource customers for a low program fee of $124. Fee may be waived for income-eligible residents. Program availability and price are subject to change. Programs are funded by a charge on utility bills.

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Energize Connecticut helps you save money and use clean energy. It is an initiative of the Energy Efficiency Fund, the Connecticut Green Bank, the State, and your local electric and gas utilities.

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ATTACHMENT I-17

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Justin May, on behalf of Eversource/Energize CT, 860-839-1539, jmay@gbpr.com

FOR IMMEDIATE RELEASE
PHOTO/CAPTION BELOW

Greenwich Residents Show Commitment to Energy Efficiency

GREENWICH, Conn. – November 23, 2016 - Nearly 230 Greenwich residents recently participated in the town's light bulb swap as part of the 2016 ENERGY STAR® Change the World Tour. Residents exchanged over 1,000 incandescent light bulbs for new, energy-efficient ENERGY STAR® LED bulbs, free of charge.

Each Greenwich resident who swapped out five of their home's old, inefficient light bulbs is expected to save more than $50 in annual energy costs. Combined, these residents will save approximately $12,000 annually. Over the lifetime of the new LED bulbs, they will collectively save approximately $265,000.

Energy experts from Eversource were on-hand at the light bulb swap to answer questions and provide information about additional opportunities to save money by making their homes more energy efficient, including information on the popular in-home service, Home Energy Solutions[SM].

"Switching from incandescent to LED light bulbs is a great first step to improve your home's energy efficiency," said Eversource's Energy Efficiency spokesman, Enoch Lenge. "We suggest that our customers also consider Home Energy Solutions to discover what other changes can be made to save money and energy."

Home Energy Solutions includes a home energy assessment and on-the-spot energy improvements performed by an Eversource-authorized contractor. The service is valued at an average of $1,000, but only costs $124; the fee is waived for income-eligible residents. A typical customer saves $200 a year following the service and will receive recommendations from their contractor for even more energy savings.

Home Energy Solutions includes:
- Sealing around doors, windows, floor joists, and any other areas where air can escape (this service alone is valued at an average of $600)
- Energy-saving light bulbs, including LEDs and CFLs
- Health and safety tests on heating and cooling equipment
- Water-saving showerheads and faucet aerators, and hot water pipe wrap

- A report detailing your home's performance before and after the changes that includes educational tips and recommendations on how to further reduce home energy costs
- Information on rebates and financing for additional upgrades including insulation, windows, appliances, and heating and cooling equipment as applicable

The Town of Greenwich is a participant in Clean Energy Communities (CEC), the nationally-recognized Energize Connecticut program that helps cities and towns save energy and increase the installation of renewable energy. Since signing the CEC pledge in 2014, Greenwich has worked with Eversource to help the town reach its energy goals and reduce municipal building energy consumption by 20 percent by 2018.

For more information on how to save energy and money at your home or business, please visit EnergizeCT.com or call 877.WISE.USE (877-947-3873).

PHOTO CAPTION: State Representatives Livvy Floren, Mike Bocchino, and Fred Camillo helped Eversource employees hand out free LED light bulbs to residents during the Greenwich Change the World Tour light bulb swap at Greenwich Town Hall.

About Energize Connecticut
Energize Connecticut helps you save money and use clean energy. It is an initiative of the Energy Efficiency Fund, the Connecticut Green Bank, the State, and your local electric and gas utilities, with funding from a charge on customer energy bills. Information on energy-saving programs can be found at EnergizeCT.com or by calling 1.877.WISE.USE.

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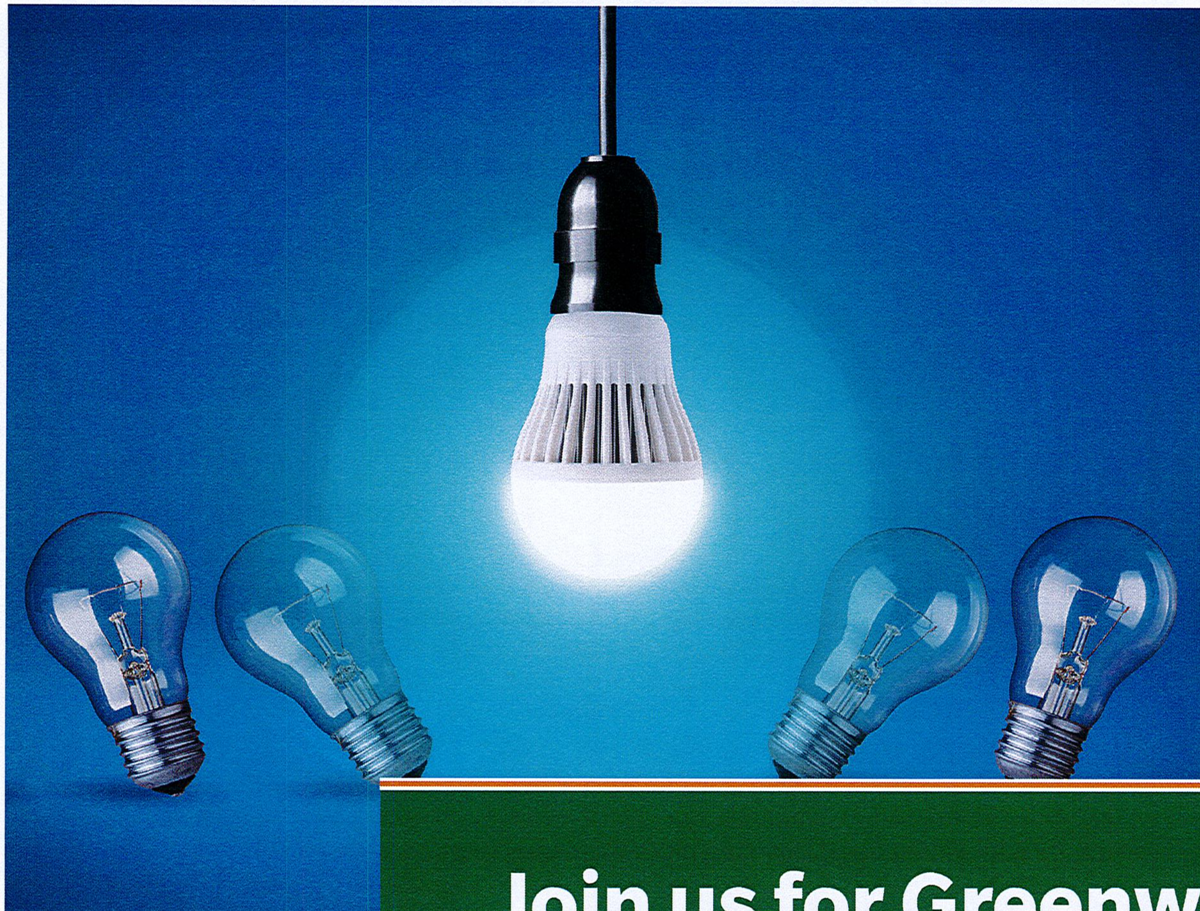
ATTACHMENT I-18



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TOWN OF GREENWICH CONSERVATION COMMISSION SINCE 1964

Join us for Greenwich's Earth Day and Light Bulb Swap on April 22nd to get 5 FREE LED bulbs!