Non-Wires Alternatives

CASE STUDIES FROM LEADING U.S. PROJECTS

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Smart Electric Power Alliance

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ABOUT SEPA

The Smart Electric Power Alliance (SEPA) facilitates the electric power industry's smart transition to a clean and modern energy future through education, research, standards and collaboration. SEPA is an unbiased, industry-trusted source for insights and knowledge on clean energy and grid modernization. Learn more at www.sepapower.org.

ABOUT PLMA

PLMA (Peak Load Management Alliance) is a non-profit organization founded in 1999 as the voice of load management practitioners. PLMA's over 140 member organizations share expertise to educate each other and explore innovative approaches to demand response programs, price and rate response, regional regulatory issues, and technologies as the energy markets evolve to represent a broad range of energy. Learn more at www.peakload.org.

ABOUT E4THEFUTURE

E4TheFuture is a nonprofit organization advancing clean, efficient energy solutions. Advocating for smart policy with an emphasis on residential solutions is central to E4TheFuture's strategy. "E4" means: promoting clean, efficient Energy; growing a low-carbon Economy; ensuring low-income residents can access clean, efficient, affordable energy (Equity); restoring a healthy Environment for people, prosperity and the planet. Dedicated to bringing clean, efficient energy home for every American, E4TheFuture's endowment and primary leadership come from Conservation Services Group whose operating programs were acquired in 2015 by CLEAResult. Visit www.e4thefuture.org.

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METHODOLOGY

In April of 2018, the Smart Electric Power Alliance (SEPA) and PLMA (Peak Load Management Alliance) received funding from E4TheFuture for a study on the current status of non-wires alternatives (NWA) projects across the United States. In particular, the goal of the study was to identify 10 representative projects and share the lessons that utilities and other industry stakeholders have learned from the process of developing and, in some cases, completing and operating these projects. To select the projects, SEPA and PLMA issued an industry-wide call for NWA case studies, and ultimately received papers on more than 25 such projects, either in development or in operation, from across the country. A peer review team of 29 volunteers scored the papers, ultimately selecting the 10 case studies with the highest rankings. Selection was based on three key criteria:

- **Applicability:** How relevant to other utilities and technology developers are the lessons learned from this NWA project? How can this project best inform utilities and be replicated?
- **Challenges identified and lessons learned:** How compelling or unique are the challenges encountered in any one project, and the resulting lessons learned, which could be shared across the industry?
- **Cross-sectional representation:** How do the projects contribute to a well-rounded set of case studies representing different geographic locations, utility or project lead types, and project sizes?

Once the 10 case studies were selected, we conducted follow-up interviews with the utilities and other project developers. The responses were put into a case study template, which was then reviewed by the individual utilities and project developers. This report is based on the original case studies submitted, and the in-depth information and insights gathered through the interviews. Available data (e.g., cost data and information on project challenges and solutions) collected through this process varied depending on the sensitivities and willingness of project participants to share information.

Executive Summary

In today's electricity market, projects such as Con Edison's Brooklyn Queens Demand Management (BQDM) initiative are capturing public attention and inspiring decision makers to examine the potential of non-wires alternatives (NWAs).[1] As interest in NWAs grows, industry practitioners are seeking out more information and lessons learned from past and existing efforts. To help shed light on a broader set of NWA projects in the U.S., E4TheFuture provided funding to the Smart Electric Power Alliance (SEPA) and PLMA (Peak Load Management Alliance) to select 10 NWA case studies and share insights from these projects with the public. Using help from 29 volunteer Peer Review Team members, the 10 case studies summarized in this report were selected based on their applicability, lessons learned, and cross-sectional representation (see Methodology for more details). These projects represent a range of technology and program solutions, project sizes, and geographies.

There are over 100 NWA projects in various planning stages today. They account for over three-quarters of total planned and completed NWA capacity in the U.S.[3] A smaller subset of NWA projects have moved into implementation stages, and an even smaller set of projects have reached completion. The 10 case studies examined in this report reflect the early stages of NWA development across the U.S. One project is still in the procurement phase, seven projects are currently active, and two projects have reached completion. Across these 10 case studies, key lessons learned and challenges surfaced along three main categories, as detailed in the table on page 8.

CASE STUDIES

Case studies (listed alphabetically by utility or key project implementer[2] if different from the utility, followed by project name):

1. Arizona Public Service (APS)—Punkin Center
2. Bonneville Power Administration (BPA)—South of Allston
3. Central Hudson Gas & Electric—Peak Perks Targeted Demand Management Program
4. Con Edison—Brooklyn Queens Demand Management (BQDM) Program
5. Consumers Energy—Swartz Creek Energy Savers Club
6. GridSolar—Boothbay
7. National Grid—Old Forge
8. National Grid—Tiverton NWA Pilot
9. Southern California Edison (SCE)—Distribution Energy Storage Integration (DESI) 1
10. SCE—Distributed Energy Storage Virtual Power Plant (VPP)

1 Non-wires alternatives are defined as "an electricity grid investment or project that uses non-traditional transmission and distribution (T&D) solutions, such as distributed generation (DG), energy storage, energy efficiency (EE), demand response (DR), and grid software and controls, to defer or replace the need for specific equipment upgrades, such as T&D lines or transformers, by reducing load at a substation or circuit level," (Navigant, 2017).

2 Key project implementer is the key project sponsor indicated in case study submissions. Most projects were led by utilities.

3 Greentech Media, A Snapshot of the US Gigawatt-Scale Non-Wires Alternatives Market, August 2017. Available at: https://www.greentechmedia.com/articles/read/gtm-research-non-wires-alternatives-market#gs.lytvWGw.

1. **Planning and Sourcing**—A number of utilities, during the initial planning and procurement phases, noted the importance of having a deep understanding of their service territories and grid conditions to help inform their program and technology procurement processes. Utilities use a "benefit to cost" assessment to evaluate NWA and other design options in order to determine the least cost alternative for consumers. In all cases, safety, reliability, customer experience and affordability should be foundational pillars for decisions on NWA options.[4] Utilities noted the importance of building in more time for the sourcing process, and the benefits of having an open and technology-agnostic approach.

   For at least two projects, NWA opportunities originally emerged as a result of high load growth forecasts; however, load growth did not materialize. These projects pointed to the uncertainty of forecasting load growth and the benefit NWAs provide in substantially reducing potential stranded costs from investing in unnecessary infrastructure upgrades.

2. **Project Implementation**—For the majority of the project teams, implementing the NWA effort meant navigating through uncharted territory. As these teams tested out new technologies and programs novel to utility customers, it was necessary to plan for internal development, reach out to local communities, and engage customers through a multipronged approach. Performance risks associated with new technologies justify the use of demonstrations and pilots to better understand performance and customer impacts, as well as exploring mechanisms for prudent sharing of risks between participants.

SUMMARY OF KEY INSIGHTS AND CHALLENGES

PLANNING AND SOURCING	IMPLEMENTATION	
	PROJECT IMPLEMENTATION	TECHNOLOGY-SPECIFIC IMPLEMENTATION
Open and technology-agnostic approaches can help with project success	Plan for internal development	Launching energy efficiency first allows longer lead times for other DER solutions
Procurement processes and bidding responses require more time than originally anticipated	Community outreach helps overall reception and likelihood of project success	Demand response encompasses a wide range of technologies and was met with varying levels of success across six case studies
Uncertainty of load growth is a challenge for utilities but a strength for NWAs	Recruitment and customer engagement requires a multipronged approach	Energy storage implementation has its share of obstacles, including: siting, reliability requirements, interconnection, and system impact challenges. These challenges are largely due to the nascency of storage technologies
Know as much about your service territory as possible to inform program recruitment		
Utilities often use a benefit-to-cost assessment to evaluate NWA opportunities		

Source: SEPA, PLMA, and E4TheFuture, 2018.

4 Note: In many states, environmental impacts must also now be considered a foundational pillar for future investments.

3. **Technology-Specific Implementation**—Projects in this study included a mix of technology solutions.[5] Case study participants noted that different technologies, their market maturity, and customer recruitment opportunities all factored into the varying levels of success when implementing these NWA projects. Customer engagement played a significant role in the varying levels of success of energy efficiency (EE) and demand response (DR) programs included in NWA solutions. For six of the case study participants leveraging electric storage, the nascency of electric storage and the inexperience of project teams led to significant lessons being learned for this technology type.

SUMMARY OF FINDINGS

While the majority of case studies examined in this report are still active or in the early stages of sourcing, a number of high-level findings became apparent:

- **Successful delays and deferrals of infrastructure upgrades**—The majority of the 10 case studies demonstrated success in helping to delay or permanently defer infrastructure upgrades.
- **Flexibility**—NWA projects offer the ability to implement solutions incrementally and in phases as load grows. This allows opportunities to approach load growth uncertainty flexibly and help avoid large up-front costs.
- **Cost Savings and Allocations**—While many of the case studies were unable to report cost data and analysis, projects such as Con Edison's BQDM and BPA's SOA demonstrated significant cost savings in implementing their NWAs in comparison to the originally proposed infrastructure investment. A major obstacle and opportunity is overcoming the traditional rate-based cost recovery model and evolving the utility business model to provide alternative revenue streams and incentives for utilities to explore benefits from DER technologies. It should be acknowledged that in many cases, this requires an update of the traditional utility compact and revenue recovery model while maintaining the commitment to providing the customer safe, reliable and affordable choices. Central Hudson's Peak Perks Program showed success with the development of a unique incentive-based compensation model rewarding both utilities and customers.

AREAS FOR FURTHER RESEARCH

As interest in NWAs continues to expand, many issues will require further utility research and discussion, including:

- NWA sourcing best practices;
- Ownership and control of NWAs;
- Utility contracting benchmarks with technology providers and third party owners;
- Navigating multiple value streams of, and cost recovery approaches for, DERs serving as NWAs;
- NWA benefit-to-cost analysis (BCA) and new incentive models for utilities;
- Beneficial electrification, its impact on the grid, and the role of NWAs.

5 Case study technology solutions included: energy efficiency (EE), demand response (DR), rooftop solar photovoltaics (PV), combined heat and power (CHP), conservation voltage optimization, thermal storage, generators, electric storage, and generation redispatch.

Introduction

A significant shift is taking place in the electric power sector today. Regulators, policy makers, and utilities are beginning to investigate and deploy alternatives to traditional transmission and distribution assets—that is, building power plants and other traditional electric infrastructure as has been done for the past 100 years. They are instead looking at non-wires alternatives, or NWAs.[6]

A number of factors have contributed to the changes now underway. The large-scale deployment and increasing cost-effectiveness of distributed energy resources (DERs) is fueling interest in NWAs. Navigant Research forecasts global spending on NWAs will grow from $63 million in 2017 to $580 million in 2026.[7] In California, New York and a number of other regions, efforts are underway to examine the potential benefits DERs and their use in NWAs can provide to transmission and distribution systems.

However, the growing interest in NWAs has revealed a major gap in current knowledge, specifically, the lack of publicly available information describing challenges and lessons learned from NWA projects. To meet this need, E4TheFuture provided funding to the Smart Electric Power Alliance (SEPA) and PLMA (Peak Load Management Alliance) to select 10 case studies of NWA projects and share information and insights regarding these initiatives with a broad range of industry stakeholders.

For many utilities and third parties leading these projects, NWAs proved to be the testing ground for new technologies, programs, and methods. These projects challenged traditional utility business models and shed light on the legislative, regulatory, and customer experience barriers that need to be addressed before NWAs can become more mainstream.

As noted in the Methodology section of this report, the NWA projects discussed here were selected based on their applicability, lessons learned, and cross-sectional representation. For each case study, key personnel at utilities and at third-party organizations shared insights regarding the planning, procurement, and implementation stages of their projects, as well as the technical and regulatory challenges they faced.

The report is broken down into four key sections:

- **Background** provides the history, a policy review, and a summary of the overall state of NWAs today. This section also includes short descriptions of the 10 NWA case studies.
- **Key Insights and Challenges** delves into the key lessons learned and findings from the 10 case studies. Insights are shared at the planning, procurement and implementation phases.
- **Conclusion** explores areas for further discussion and research.
- **Appendix** provides the 10 NWA case studies in their entirety, and resources for further reading.

6 NWAs are generally defined as the use of non-traditional solutions (e.g., distributed energy resources) to help defer or replace traditional infrastructure investments (see next section for a full definition).

7 Non-Traditional Transmission and Distribution Solutions: Market Drivers and Barriers, Business Models, and Global Market Forecasts, Navigant, 2017. Available at: https://www.navigantresearch.com/reports/non-wires-alternatives.

Background

While NWAs have recently become a focus of discussions across the electric power industry, the concept of non-wires alternatives has been around for over three decades.[8] Earlier opportunities for NWA development were often talked about as “targeted demand-side management” or other aliases, the objective of which was to offset distribution investment. Bonneville Power Authority (BPA) started exploring NWA opportunities in the Pacific Northwest as early as 1987 and has since considered over 150 potential NWA projects.[9] To date, however, BPA has implemented just three of these projects. In California, Pacific Gas and Electric (PG&E) developed its first NWA in 1991 as a targeted demand-side management measure.[10]

Renewed interest in NWAs is taking place today in large part due to the widespread deployment of DERs and the potential to leverage their multiple capabilities. Efforts to reform the traditional utility business model, respond to forecasted load growth, and integrate DERs are leading to a growing number of of opportunities for NWA projects. In some instances, these projects are being driven by state-level regulatory processes; in others, utilities and other industry stakeholders are independently assessing and testing strategic, locational deployment of DERs.

DEFINING NON-WIRES ALTERNATIVES

Non-wires alternatives is one of several terms now used to refer to the use of DERs in place of traditional power plants and infrastructure. Other terms include *non-wires solutions* (NWS) and *non-transmission alternatives* (NTA). NWA remains the most commonly used term, which is our main reason for using it in this report. Our working definition of NWAs comes from Navigant:

> *Non-wires alternatives is defined as “an electricity grid investment or project that uses non-traditional transmission and distribution (T&D) solutions, such as distributed generation (DG), energy storage, energy efficiency (EE), demand response (DR), and grid software and controls, to defer or replace the need for specific equipment upgrades, such as T&D lines or transformers, by reducing load at a substation or circuit level.”*[11]

8 Most utilities currently consider new technologies and applications through a BCA formula that considers foundational pillars of safety, reliability customer experience, affordability and more recently environmental impacts.

9 BPA, Non-Wires Alternatives to Transmission, 2003. Available at: https://aceee.org/files/pdf/conferences/eer/2003/Hoffman-CPAw.pdf.

10 The PG&E Model Energy Communities Program: Offsetting Localized T&D Expenditures with Targeted DSM, 1992. Available at: https://aceee.org/files/proceedings/1992/data/papers/SS92_Panel5_Paper17.pdf.

11 Navigant, Non Wires Alternatives, 2017.

NWAs: HOW ARE THEY DIFFERENT FROM VIRTUAL POWER PLANTS AND MICROGRIDS?

The difference between NWAs, virtual power plants (VPPs) and microgrids remains a point of some confusion within the industry.

- **VPPs** rely on software and advanced communication systems to aggregate, control, dispatch, plan, and optimize a suite of DERs to provide services similar to a conventional power plant.[12]
- **Microgrids** are comprised of a group of interconnected loads and DERs within clearly defined electrical boundaries. A microgrid can act as a single controllable entity with respect to the grid, and can connect or disconnect from the grid to operate in both grid-connected and "island" mode.[13]

Certainly, some NWA projects include VPPs and microgrids. In fact, one of the case studies in this report is referred to as a virtual power plant. VPPs and microgrids also have the potential to reduce constraints on existing T&D infrastructure and help avoid the needs for system upgrades.

However, a distinction can be drawn based on the purpose and goals of a project. The NWAs discussed in this study were developed explicitly to defer or replace grid infrastructure upgrades, while VPPs and microgrids are traditionally developed for a variety of other purposes.

SEPA, PLMA, and E4TheFuture look forward to working with industry peers to align terminology to prevent confusion among stakeholders and provide clear distinctions between the purposes for each end use of DER technologies.

STATE OF THE NON-WIRES ALTERNATIVES MARKET

Global spending on NWAs is forecasted to grow from $63 million in 2017 to $580 million in 2026, according to Navigant Research.[14] While some U.S. utilities are choosing to explore NWA opportunities on their own, a significant number of projects are the result of state-level regulatory processes and public-private partnerships, as outlined in Table 1.

Regulatory processes have had the biggest impacts in California and New York—states which have long provided models for industry-wide changes later adopted in many other states.

- In **California**, high levels of DER penetration have begun to cause operational grid issues. As of the end of 2017, there was over 7 gigawatts (GW) of cumulative distributed solar capacity in the state.[15] CPUC's guidance for developing distribution resource plans (DRPs) requires utilities to assess the grid impacts of DERs and optimize utility operations and planning processes.
- In **New York**, the REV initiative is in the process of overhauling the traditional utility business model so that utilities will become distribution system platform providers.[16] In addition, the REV has made utility planning processes more transparent. As of May 2018, New York utilities had 41 current and upcoming NWA procurements listed on the REV Connect site.[17]

12 SEPA, Virtual Power Plants: Buzzword or Breakthrough?, November 2016. Available at: www.sepapower.org.

13 U.S. Department of Energy definition, https://building-microgrid.lbl.gov/microgrid-definitions. See also SEPA and EPRI, December 2016, Microgrids: Expanding applications, implementations, and business structures, www.sepapower.org.

14 Navigant, Non-Wires Alternatives, 2017. Available at: https://www.navigantresearch.com/reports/non-wires-alternatives; see also https://www.utilitydive.com/news/non-wires-alternatives-whats-up-next-in-utility-business-model-evolution/446933/.

15 SEPA, 2018 Utility Solar Market Snapshot, 2018. Available at: https://sepapower.org/resource/2018-utility-solar-market-snapshot/.

16 ScottMadden, California and New York Demonstration Projects, 2017.

17 NYREV, accessed 9/12/2018, available at: https://nyrevconnect.com/non-wires-alternatives/.

TABLE 1: STATE-LEVEL REGULATORY PROCESSES FOR NWAs

CALIFORNIA 	The California Public Utilities Commission (CPUC) has approved a number of NWA-related actions, including: ▪ Providing guidance to the state's investor-owned utilities (IOUs) regarding development of distribution resource plans (DRPs) that "identify optimal locations for the deployment of distributed resources."[18] ▪ Approving a pilot regulatory incentive mechanism that awards a 3-4% pre-tax incentive to utilities deploying cost-effective DERs that defer or displace traditional distribution investments.[19] ▪ Directing California IOUs to procure at least 150 MW of "preferred resources," such as EE, solar PV, or energy storage resources.[20]
NEW YORK 	In 2014, New York launched a set of regulatory proceedings and policy initiatives known as Reforming the Energy Vision (REV). One of REV's key goals is to incentivize utilities to leverage the deployment of DERs to address problems traditionally handled by new investments in centralized generation, transmission, and distribution infrastructure.[21]
RHODE ISLAND 	In 2006, Rhode Island enacted a requirement for utilities to file annual System Reliability Procurement reports. As part of this process, utilities have to consider NWAs. The state's major distribution utility is also allowed to recover costs of investments in system reliability.[22]
VERMONT 	The Vermont Public Utility Commission enacted legislation in 2015 requiring the Vermont System Planning Committee to identify deferral projects when considering new transmission.[23]
MAINE 	The state's Smart Grid Policy Act Directive requires regulators to consider NWAs before approving T&D projects. As of 2016, Maine has also designated a non-transmission alternative (NTA) coordinator to establish an independent investigator responsible for identifying cost-effective projects.[24]

Source: SEPA, PLMA, and E4TheFuture, 2018.

18 CPUC Public Utilities Code Section 769 issued on August 14, 2014.

19 Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot, Decision 16-12-036, CPUC, December 15, 2016.

20 Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long Term Procurement Plans, California Public Utilities Commission, 2014. Available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K008/89008104.PDF.

21 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, New York Department of Public Service, 2014. Available at: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/C12C0A18F55877E785257E6F005D533E?OpenDocument.

22 Rhode Island Office of Energy Resources, System Reliability Program. Available at: http://www.energy.ri.gov/reliability/.

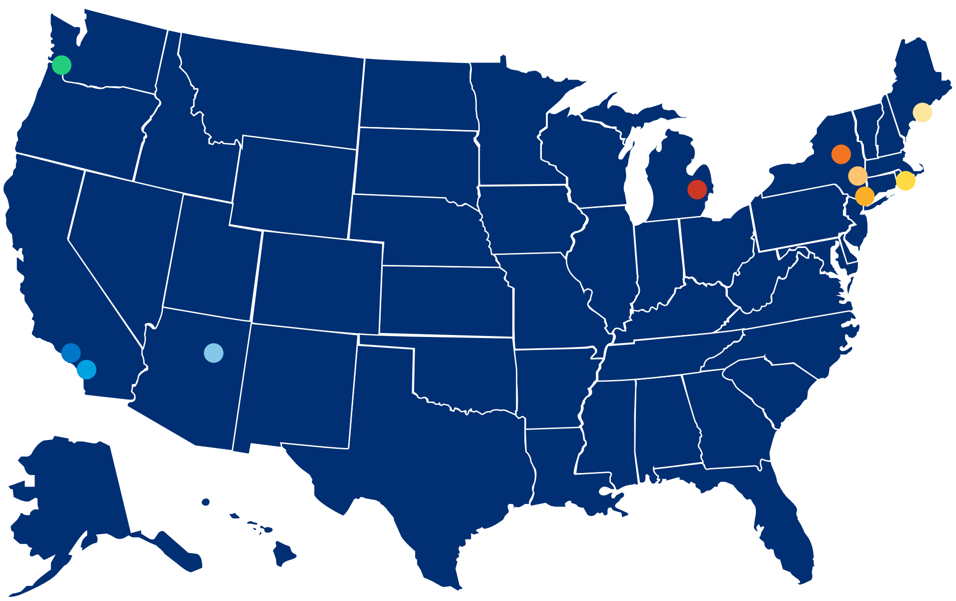
23 Northeast Energy Efficiency Partnerships, EM&V Forum and Policy Brief: State Leadership Driving Non-Wires Alternative Projects and Policies, 2017. Available at: https://neep.org/sites/default/files/resources/NWA%20brief%20final%20draft%20-%20CT%20FORMAT.pdf

24 Maine Public Utilities Commission, Docket No. 2016-00049, Commission Initiated Investigation into the Designation of a Non Transmission Alternative Coordinator, March 2016. Available at: https://mpuccms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2016-00049.

The NWA market is still nascent, but the number of proposed or potential projects is growing. Some stakeholders see NWAs as a cost effective opportunity to help meet the power needs of a region and provide environmental benefits. However, utilities have long relied on traditional solutions. They may be skeptical and resistant to looking at non-traditional options. From their perspective, it is an obstacle to look beyond current practices unless there are updates to the regulatory compact and associated revenue recovery models that reward performance and establish accountability for customer satisfaction.

FEATURED CASE STUDIES

FIGURE 1: MAP OF TOP SELECTED NWA CASE STUDIES



BPA—SOUTH OF ALLSTON
ALLSTON, WA

SCE—VIRTUAL POWER PLANT
LOS ANGELES, CA

SCE—DESI 1
ORANGE, CA

APS—PUNKIN CENTER
PUNKIN CENTER, AZ

CONSUMERS ENERGY—SWARTZ CREEK ENERGY SAVERS
SWARTZ CREEK, MI

NATIONAL GRID—OLD FORGE
OLD FORGE, NY

CENTRAL HUDSON GAS & ELECTRIC—PEAK PERKS PROGRAM
MID-HUDSON RIVER, NY

CON ED—BROOKLYN QUEENS DEMAND MANAGEMENT
BROOKLYN, NY

NATIONAL GRID—TIVERTON NWA PILOT
TIVERTON/LITTLE COMPTON, RI

GRIDSOLAR—BOOTHBAY PILOT
BOOTHBAY PENINSULA, ME

Source: SEPA, PLMA, and E4TheFuture, 2018.

SELECTED NON-WIRES PROJECTS

Case studies (listed alphabetically by utility and key project implementer if different from the utility, followed by project name):

1. Arizona Public Service (APS)—Punkin Center
2. Bonneville Power Administration (BPA)—South of Allston (SOA)
3. Central Hudson Gas & Electric—Peak Perks Targeted Demand Management Program
4. Con Edison—Brooklyn Queens Demand Management (BQDM) Program
5. Consumers Energy—Swartz Creek Energy Savers Club
6. GridSolar—Boothbay
7. National Grid—Old Forge
8. National Grid—Tiverton NWA Pilot
9. Southern California Edison (SCE)—Distribution Energy Storage Integration (DESI) 1
10. SCE—Distributed Energy Storage Virtual Power Plant

CASE STUDY OVERVIEW AND COMMONALITIES

The case studies profiled in this study encompass a broad range of project types and characteristics:

- **Project sizes** include transmission-level NWAs providing 100 megawatts (MW) of load relief, as well as distribution-level NWAs ranging from 330 kilowatts (kW) to 85 MW.
- **Status** of projects ranges from complete, currently active, and early procurement phases.
- **Technologies and programs** include a mix of behind-the-meter and front-of-the-meter solutions. Behind-the-meter solutions include EE, DR, rooftop solar PV, combined heat and power (CHP), conservation voltage optimization, thermal storage, generators, and electric storage. Front-of-the-meter solutions include energy storage and generation redispatch. (See Table 2 or Appendix).
- **Results and Outcomes** of these projects were positive for the most part. They successfully helped delay or permanently defer infrastructure upgrades.

Table 2 provides a detailed list of each project's size, status, and technology portfolio.

Each of these projects has unique elements, based on regulatory environment, service territory, and specific grid constraints and conditions. However, a handful of key commonalities became evident among many of them:

- **Regulatory mandates played a large role in over half of the 10 case studies.** For projects in states such as New York and California, broader policy initiatives, such as New York's REV and California's DRPs, are challenging traditional utility business models and pushing utilities to look at ways to leverage DERs to optimize operations and planning processes.

  For a few case studies, direct regulatory mandates came as a result of a third-party challenging a utility's rate case filing and winning commission approval to explore clean energy and NWA opportunities.

ALTERNATIVE UTILITY REVENUE STREAMS AND INCENTIVES FOR NWAs: PROVIDING CERTAINTY IN AREAS OF UNCERTAINTY

For many NWA efforts taking place across the U.S., overcoming the traditional utility compensation model of obtaining an established rate of return on traditional capital investments is a major hurdle. Further, NWA projects require more effort to design and execute than most traditional upgrades. In order for the utility industry to be motivated to explore NWA opportunities, alternative revenue streams and incentives, opportunities for demonstrations and testing, consideration of new service offerings and clear understanding of procedural and performance responsibilities are needed. Some examples include:

- Performance-based regulation that could include some financial incentive, for example associated with congestion-cost management, environmental impact, reliability, or resiliency, that potentially could yield more revenue than a fixed rate of return (i.e., higher risk, but higher reward);
- Utility revenue-sharing on NWA savings;
- Providing greater clarity regarding utility ownership or compensation for NWAs, particularly in deregulated states, so that financial compensation opportunities are more transparent;
- Addressing concerns associated with revenue opportunities in areas of the country where high levels of DR and EE investments already exist. This could be done by developing policies and regulations that account for these limitations as part of the incentive design.

TABLE 2: NON-WIRES ALTERNATIVES CASE STUDIES BY PROJECT SIZE, STATUS, AND TECHNOLOGIES

UTILITY, KEY PROJECT IMPLEMENTER—PROJECT NAME	PROJECT SIZE	STATUS	ENERGY EFFICIENCY	DEMAND RESPONSE	SOLAR PV	ENERGY STORAGE	GENERATION	BACKUP GENERATORS	FUEL CELLS	COMBINED HEAT AND POWER	CONSERVATION VOLTAGE OPTIMIZATION	NOTES
ARIZONA PUBLIC SERVICE—PUNKIN CENTER	2 MW, 8 MWh	A: Q1 2018				●						
BONNEVILLE POWER ADMINISTRATION—SOUTH OF ALLSTON	200 MW Inc. 200 MW Decr. 100 MW Relief	A: July 2017 T: Sept. 2018		●			●					
CENTRAL HUDSON GAS & ELECTRIC—PEAK PERKS DEMAND MANAGEMENT PROGRAM	16 MW	A: 2016		●				●				
CON EDISON—BROOKLYN QUEENS DEMAND MANAGEMENT (BQDM) PROGRAM	52 MW	A: 2014	●	●	●	●			●	●	●	
CONSUMER ENERGY—SWARTZ CREEK ENERGY SAVERS CLUB	1.4 MW	A: Oct. 2017	●	●								
GRIDSOLAR—BOOTHBAY	1.85 MW	A: Q4 2013 T: Q2 2018	●	●	●	●		●				Thermal and electric storage
NATIONAL GRID—OLD FORGE	19.8 MW, 63.1 MWh	In development				●						
NATIONAL GRID—TIVERTON NWA PILOT	330 kW	A: 2012	●	●								
SOUTHERN CALIFORNIA EDISON—DISTRIBUTION ENERGY STORAGE INTEGRATION (DESI) 1	2.4 MW, 3.9 MWh	A: May 2015			●							
SOUTHERN CALIFORNIA EDISON—VIRTUAL POWER PLANT (VPP)	85 MW	A: Dec. 2016		●		●						Storage systems applied as DR

Note: Status indicates when project started. A: Active; T: Terminated.

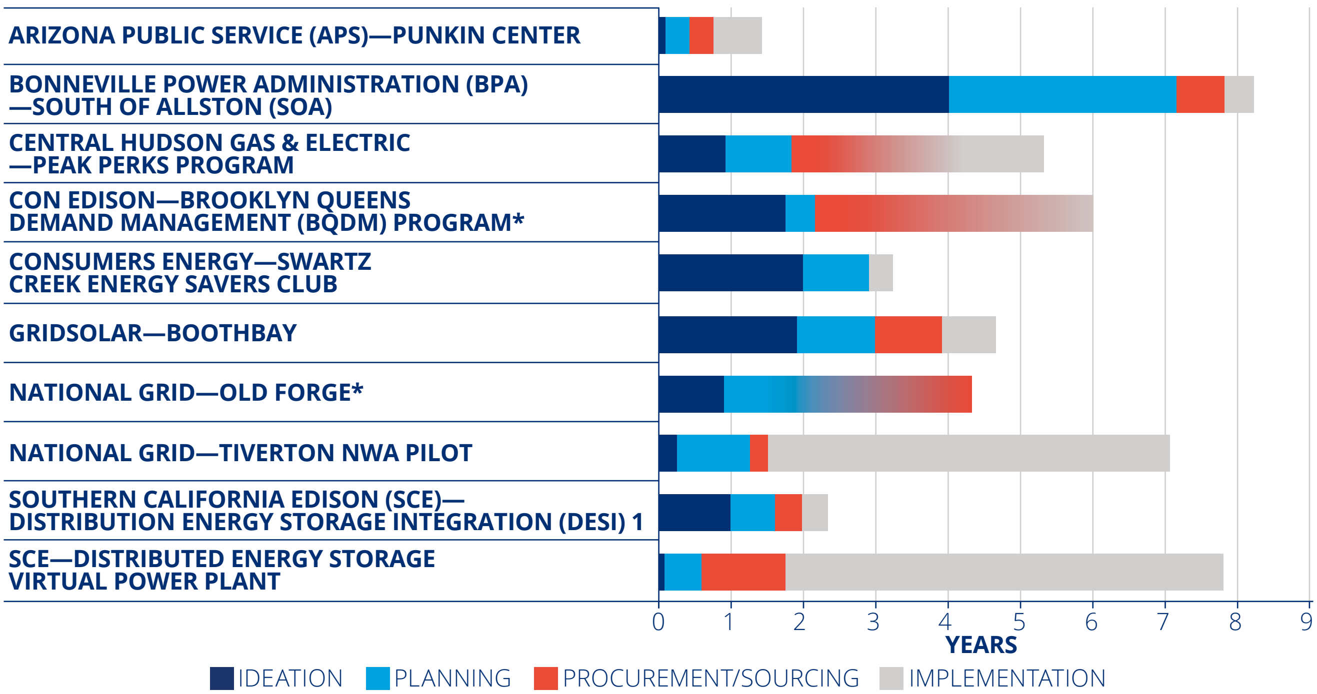
Source: SEPA, PLMA, and E4TheFuture, 2018.

CASE STUDY PROJECT TIMELINES

Projects' timelines for NWA projects varied based on the scale of the project and the technologies or programs selected to implement. For a number of cases, a significant amount of time was spent ideating and examining the viability of an NWA solution. Similarly, the planning phases ranged from four months to 38 months. Procurement fell on average from three months to 11 months.

For some utilities with larger portfolios of solutions or customer programs (e.g., DR and EE), the procurement process was an iterative one, occurring alongside implementation. Implementation was, in some cases, much clearer when installing a battery, whereas it took longer when requiring customer recruitment for DR programs.

FIGURE 2: CASE STUDY PROJECT TIMELINES



Note: Project timeline information and detail varied widely across the 10 case studies. This figure was developed with input from utilities to provide a high level picture of project timelines. More detailed project timelines are available upon request.

*Additional notes: For BQDM, multiple programs contribute to the BQDM portfolio, and thus timelines for procurement and implementation are ongoing. National Grid's Old Forge is currently in the planning and procuring phases. BPA's South of Allston, GridSolar's Boothbay and National Grid's Tiverton NWA Pilot are the only three projects of the 10 that have been fully wrapped up.

Definitions for timeline phases:

- **Ideation:** The more informal period of discussing and exploring potential for NWA solutions to address reliability concerns, increased load forecasts, or deferment of new transmission and distribution investments.
- **Planning:** The time involved in identifying needs of the system and developing criteria for a non-wires project and preparing for sourcing solutions.
- **Procurement/Sourcing:** The time needed to develop, release, and conclude negotiations for proposals of a non-wires alternative project, primarily through competitive solicitation or a customer program.
- **Implementation/Construction:** The time needed to recruit customers for EE and DR programs, as well as deploy new assets (e.g., electric storage).

Source: SEPA, PLMA, and E4TheFuture, 2018.

- **Internal management decisions also played a significant role in NWA projects.** A number of projects came to fruition due to an internal management decision influenced by regulatory mandates (e.g., CPUC's preferred resources pilot). Other NWA opportunities were primarily driven by internal management decisions to explore alternatives to large-scale generation or grid upgrade projects.
- **Sourcing across the 10 case studies** was predominantly through direct procurement, either single-source or competitive bidding processes.

TABLE 3: T&D CHALLENGES, DRIVERS, AND SOURCING

UTILITY, KEY PROJECT IMPLEMENTER—PROJECT NAME	T&D CHALLENGE	DRIVERS	SOURCING
ARIZONA PUBLIC SERVICE—PUNKIN CENTER	Thermal constraint on feeder	Regulatory Mandate, Internal Management Decision	Direct procurement (competitive bidding)
BONNEVILLE POWER ADMINISTRATION—SOUTH OF ALLSTON	Transmission grid constraint	Internal Management Decision	Direct procurement
CENTRAL HUDSON GAS & ELECTRIC—PEAK PERKS DEMAND MANAGEMENT PROGRAM	Distribution constraint	Regulatory Mandate	Customer Program
CON EDISON—BROOKLYN QUEENS DEMAND MANAGEMENT (BQDM) PROGRAM	Sub-transmission feeder constraint at substation	Regulatory Mandate, Internal Management Decision	Customer Program
CONSUMERS ENERGY—SWARTZ CREEK ENERGY SAVERS CLUB	Distribution constraint	Regulatory Mandate, Internal Management Decision	Customer Program
GRIDSOLAR—BOOTHBAY	Distribution constraint and reliability	Regulatory Mandate, Internal Management Decision, Public Input	Direct procurement (competitive bidding, sole-sourced)
NATIONAL GRID—OLD FORGE	Distribution constraint and grid resiliency	Internal Management Decision	Direct procurement (competitive bidding, sole-sourced)
NATIONAL GRID—TIVERTON NWA PILOT	Feeder substation upgrade deferral	Internal Management Decision	Customer Program
SOUTHERN CALIFORNIA EDISON—DISTRIBUTION ENERGY STORAGE INTEGRATION (DESI) 1	Distribution constraint	Internal Management Decision	Direct procurement (competitive bidding, sole-sourced)
SOUTHERN CALIFORNIA EDISON—VIRTUAL POWER PLANT (VPP)	Long term local capacity constraints	Internal Management Decision with Regulatory Mandate	Direct procurement (competitive bidding, sole-sourced)

Note: In a majority of case studies, NWA solutions were procured through competitive solicitations (e.g., RFI and RFPs). A subset of these case studies leveraged existing customer programs (e.g., EE and DR) to help meet NWA objectives.

Source: SEPA, PLMA, and E4TheFuture, 2018.

CASE STUDY SUMMARIES

APS—PUNKIN CENTER

At Punkin Center, Arizona, APS was faced with the traditional option of rebuilding 17 miles of distribution lines over rough terrain to address load growth and consequent thermal constraints on the feeder. After reviewing the growing community's needs, APS determined that adding battery storage could address the problem at a lower cost. The utility deployed a 2 MW, 8 megawatt-hour (MWh) battery system that has been in daily operation since March 2018.

The Punkin Center project required high reliability, which led APS to plan the deployment and operation of the battery system to provide several layers of redundancy and flexibility for future expansion. Spares of critical items with long procurement lead-times, such as an extra transformer, were kept on-site. The site was configured to connect a diesel generator in case of a contingency event. In addition, the project was designed with additional concrete pads for the future addition of battery capacity to meet load growth. APS also ran up against a number of challenges during the first operating summer, including the development of a battery dispatch method for peak shaving, the impact of battery ramp limitations due to the Integrated Volt/VAR Control (IVVC) voltage control scheme and high feeder impedance, and operational considerations for reverse power flow situations. Overall, APS considered this effort as proof that cost-effective NWA projects using energy storage can be successful and should be in the utility planner's toolbox.

Outcome: The Punkin Center battery project successfully provided reliable peak shaving service on the thermally constrained feeder during the summer of 2018. The project proved to be a cost-effective solution for APS to serve the rural community, compared to reconductoring of the line. The success of the project demonstrates the capability of this NWA solution to serve the residents of Punkin Center for a decade and possibly longer depending on the load growth.

Source: Arizona Public Service, 2018.

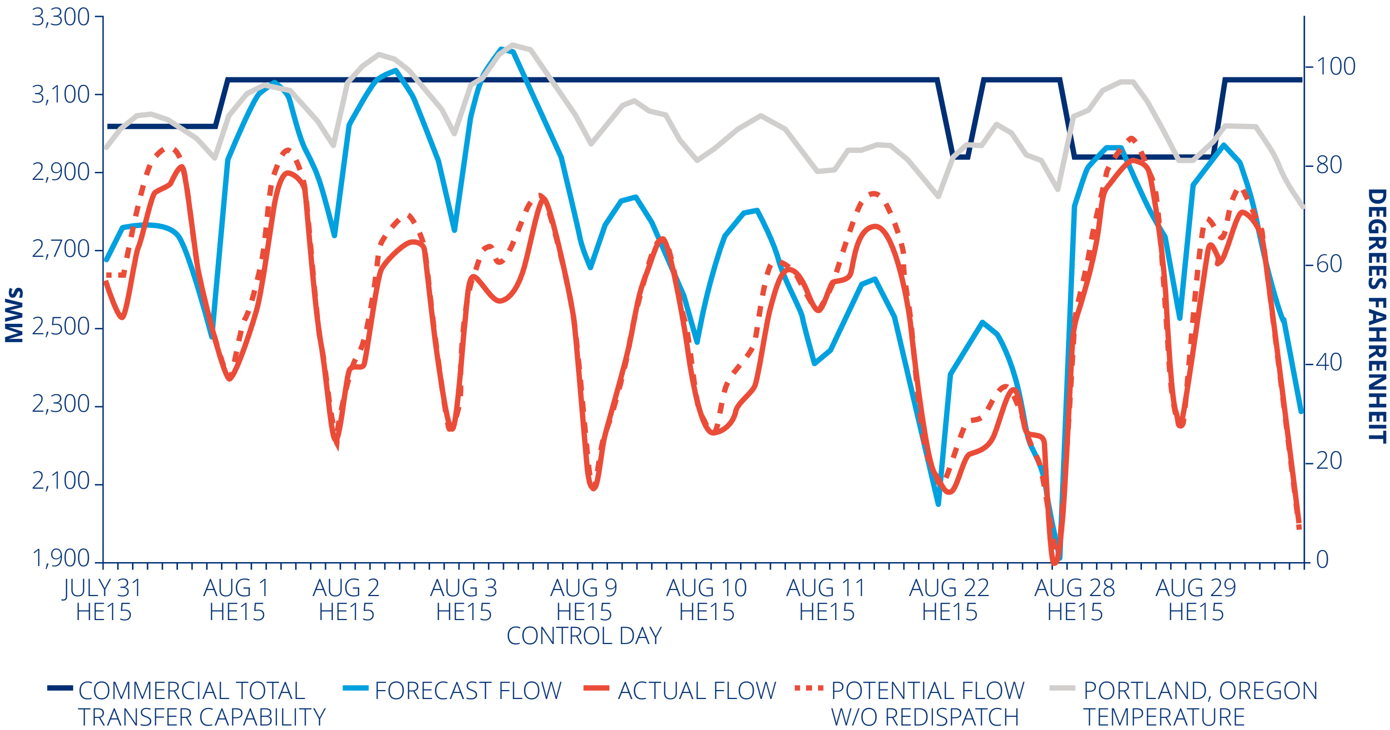
BPA—SOUTH OF ALLSTON

Faced with projections of growing demand on its transmission system, BPA originally proposed the I-5 Corridor Reinforcement Project in 2009. At that time, the plan involved construction of an 80-mile, 500 kilovolt (kV) transmission line that would stretch from Castle Rock, Washington to Troutdale, Oregon and cost more than $1 billion. This transmission project faced community opposition and heightened legislative scrutiny due to its high cost and local impacts.

After taking a comprehensive look at the local impacts of the build-out and other project details, such as load forecasts and project costs, the BPA Administrator decided not to carry out the I-5 project and instead embraced a more flexible, scalable, economically and operationally efficient approach to managing the transmission system. The NWA project included two basic types of solutions: DR centered on a large commercial and industrial (C&I) end user, and generation redispatch.[25]

25 Generation redispatch at BPA consisted of bilateral purchases of incremental and decremental capacity from existing commercial generators to alleviate congestion by reducing power transmitted along a path and increasing the amount of generation closer to load.

FIGURE 3: SOUTH OF ALLSTON 2017 SUMMER PEAK FLOWS



Note: HE15: Hour Ending 15 (the hour from 14:00 to 15:00)

Source: Bonneville Power Administration, 2018.

The South of Allston (SOA) pilot ran for two years and operated on a day-ahead, pre-schedule basis on weekdays in the summer months of July, August and September to balance roughly 200 MW of increased generation south of the transmission line and 200 MW of reduced load north of the line to reduce transmission constraints.

Outcome: The SOA project met BPA's original objective to demonstrate that flows across SOA can be reduced during summer peak periods through bilateral contracts. The 2017-2018 SOA project expenses were each within the $5 million per year transmission budget amount (compared to the originally proposed $1 billion transmission line). BPA plans to leverage lessons learned from the SOA Pilot to inform future longer-term, non-wires program plans.

CENTRAL HUDSON GAS & ELECTRIC—PEAK PERKS PROGRAM

Central Hudson's Peak Perks Targeted Demand Management Program was designed in conjunction with the New York Public Service Commission's REV initiative. The program seeks to defer the need for new infrastructure in three targeted zones for five to 10 years, reduce future bill pressure for customers, and create additional earnings opportunities for the utility.

The program consists of residential direct-load control using two-way Wi-Fi thermostats and one-way load control switches. A special initiative focused on industrial facilities and others that could make curtailment commitments and shut down their facilities when needed. Residential customers with electric generators fueled by propane and natural gas also received annual payments to switch to their generators during peak events. Itron provided participant recruitment and program administration support, as well as its cloud-based IntelliSOURCE software as the foundation for the project.

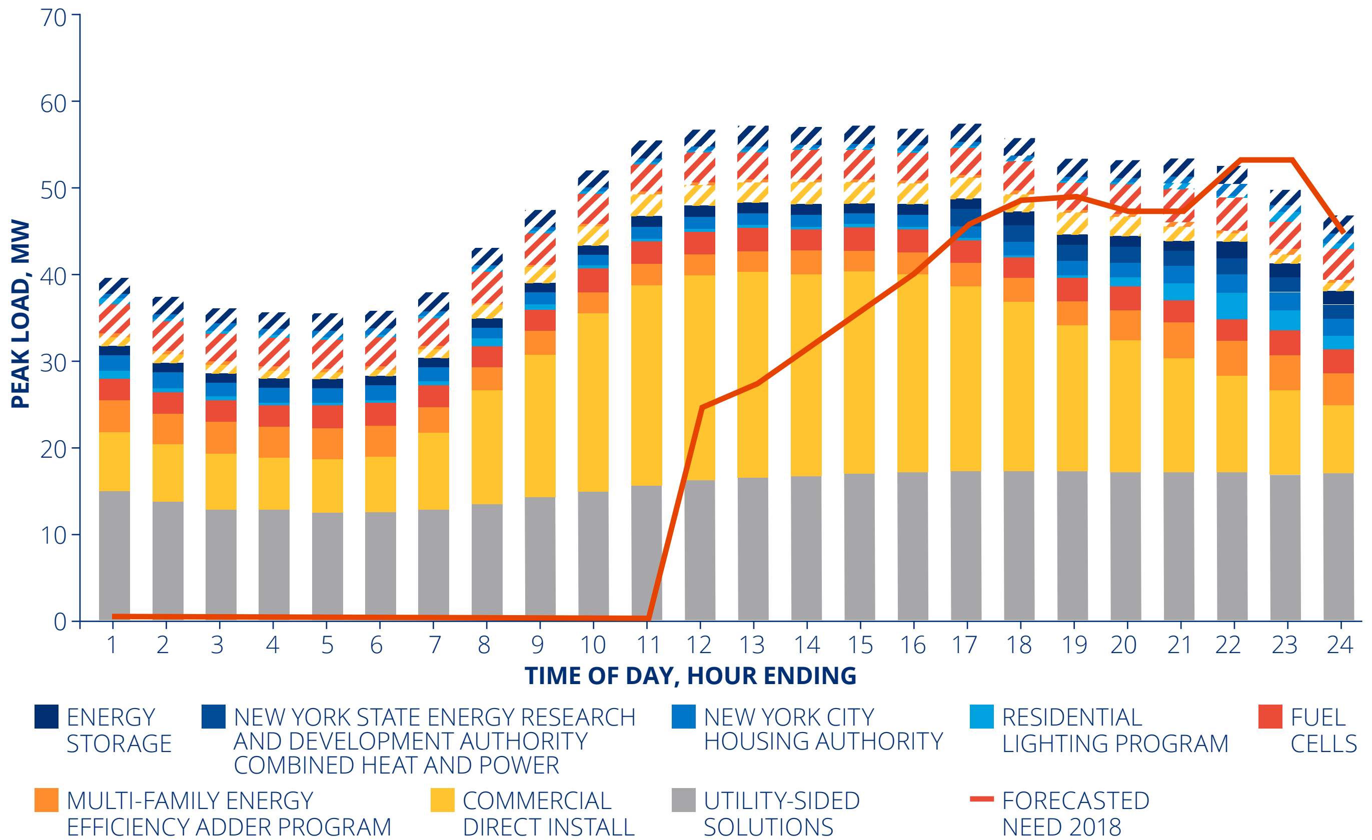
Outcome: In the first six months of the program, Central Hudson achieved over 30% participation of eligible customers within Fishkill, the targeted zone with the greatest capacity need. The utility also exceeded the total first-year MW target for all three zones, achieving 5.9 MW of load reduction compared to the original target of 5.3 MW.

CON EDISON—BROOKLYN QUEENS DEMAND MANAGEMENT PROGRAM

The Brooklyn Queens Demand Management Program (BQDM) is one of the largest and most well-known NWA projects in the U.S, with close to 52 MW of traditional and non-traditional resources. This project was designed to help delay the construction of a new substation beyond initial load relief projections. This project on its own has been a driver and leader for NWAs as other utilities and regulators learn more about the benefits resulting from this project and begin to explore opportunities themselves.

Con Edison's traditional approach to potential overload conditions would have been to construct a new area substation, establish a new switching station, and construct sub-transmission feeders. Instead, Con Edison filed a petition with the New York Public Service Commission in July 2014 proposing to implement the BQDM Program, which would consist of 11 MW of non-traditional utility-side solutions and 41 MW of traditional

FIGURE 4: EXAMPLE OF HOURLY LOAD REDUCTION PROVIDED BY DIFFERENT NWA RESOURCES



Source: Con Edison, 2018.

customer-side solutions. This program was approved with a $200 million budget. BQDM's portfolio includes a combination of EE, DR, distributed generation, and energy storage technologies. The company's first direct solution buying actions were the Energy Efficiency Portfolio Standard (EEPS) Commercial Direct Install (CDI) and Multi-family Energy Efficiency (MFEE) adders.[26]

Energy efficiency programs within the New York City Housing Authority and other New York City Agencies offer opportunities for high levels of demand reduction and have yielded peak load reductions of more than 1.6 MW, with additional load reductions expected through the end of 2018. Fuel cells, CHP, and DR have offered over 6 MW of deliverable peak load reduction capacity.

The scale and wide scope of portfolio technologies leveraged in this program have provided a number of insights and lessons learned. A primary lesson is that launching into new and more complex technologies often requires longer lead times. In addition, having a portfolio of options allowed Con Edison to manage risks, adopt diverse technologies, and engage various customers and solution providers.

Outcome: The project successfully deferred the need for a substation upgrade that would have cost $1.2 billion. Con Edison received an extension in 2017 to continue implementation of the BQDM program to defer additional traditional investments and deliver additional benefits to customers.[27] The BQDM program also increased levels of engagement with customers and vendors. Some local employers have also referenced the program as a driver for new jobs in the area.

CONSUMERS ENERGY—SWARTZ CREEK ENERGY SAVERS CLUB

The Swartz Creek Energy Savers Club came about at the request of the Natural Resources Defense Council (NRDC). Through this agreement, Consumers Energy was asked to develop a pilot project to investigate opportunities to use EE and DR to avoid or defer distribution system investments and provide cost savings for customers. Consumers Energy recruited residential customers to cycle their air conditioners and adopt EE measures. This project's goal was to reduce load requirements below the 80% maximum summer capacity (reduce peak load by 1.4 MW by 2018 or 1.6 MW by 2019) and defer a $1.1 million infrastructure investment.

The project kicked off in October 2017 and included multiple components: an Energy Ambassador who gathered intelligence and garnered participation via outreach; an Energy Task Force which worked to engage local stakeholders; as well as a multi-channel marketing campaign. Early results show the project is having a positive impact on reducing demand through increased program participation; however, projected participation in EE and DR for 2018 will not meet 2018 goals. Recruitment of commercial and industrial customers has been particularly challenging, with mostly small businesses in the area facing economic limitations and holding inflexible load profiles. Additionally, the largest

26 The CDI Adder initiative engaged commercial customers with a peak demand of 300 kW or less and contributed to peak hour load relief of 11.4 MW as of June 30, 2018 from over 6,000 customers. The MFEE adder, originally a part of the EEPS, identified load-reduction measures and offered incentives for multi-family dwellings of five or more units. The program was extended under the Energy Efficiency Transition Implementation Plan (ETIP) in 2016, with the Company's continued implementation resulting in a total of over 1,500 buildings that have contributed to a BQDM peak hour load relief of 4.7 MW by June 30, 2018. The C&I EE program offers incentives to commercial and industrial facilities with over 300 kW monthly peak load. Con Edison's residential EE programs included a lighting program and Bring Your Own Thermostat (BYOT) programs. The lighting program initially had a 2 MW peak load reduction goal over a 12-month implementation timeframe. However, the company extended contracts to continue implementation until the end of 2018. Implementation in this program has resulted in approximately 3.1 MW of peak load relief by June 2018, while the BYOT programs achieved peak load relief of 118 kW by the end of the second quarter of 2018.

27 NYPSC, Case 14-E-0302 Order Extending Brooklyn Queens Demand Management Program, 2017. Available at: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B6790B162-8684-403A-AAE5-7F0561C960CE%7D.

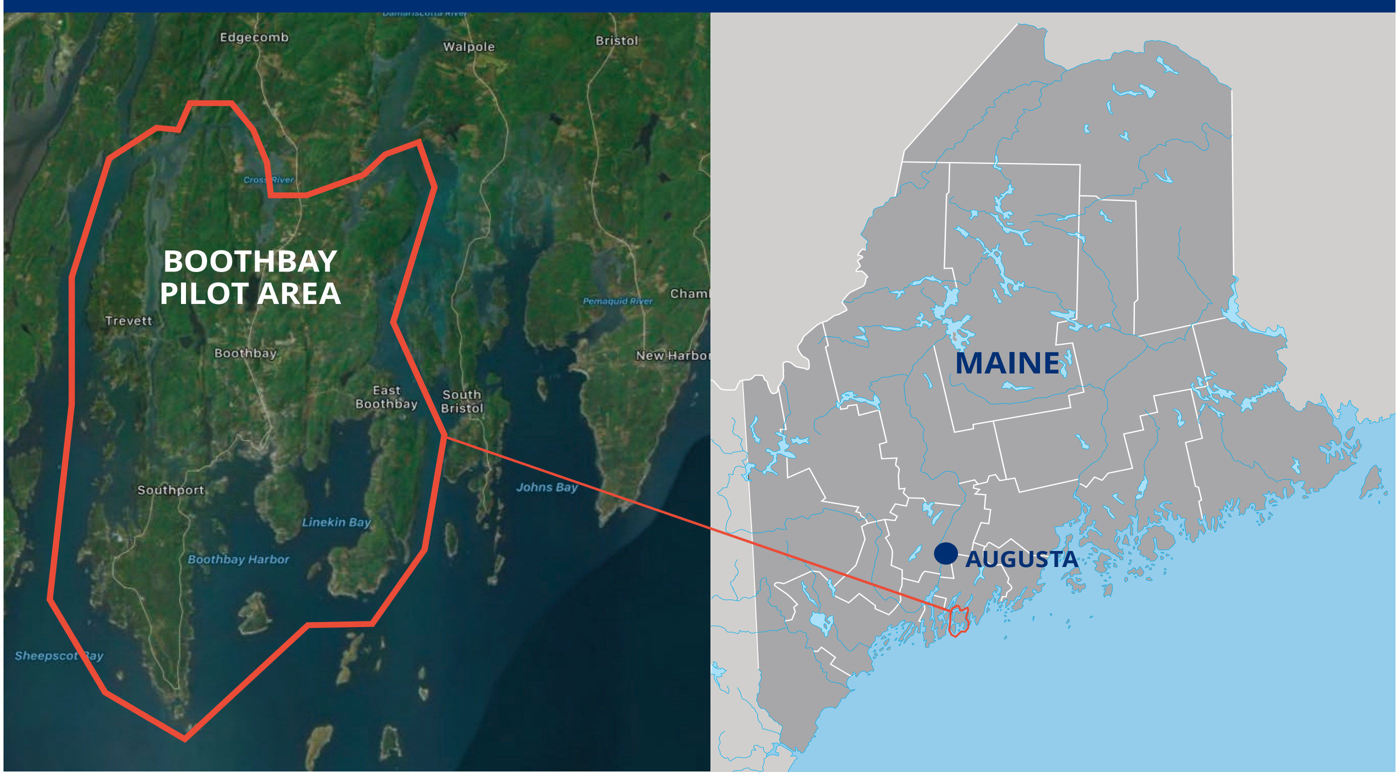
C&I customer opted out of participation.[28] The majority of energy savings achieved to date have come from commercial lighting programs and residential DR. NRDC and Consumers Energy are looking for more opportunities for EE savings and options to add bonus incentives to existing programs to help meet targets.

Outcome: Consumers Energy's goal was to reduce load requirements below 80% maximum summer capacity. While the project is helping to reduce demand through increased program participation, projected participation goals are currently below targets. The project is still active, and the team is currently exploring additional opportunities to meet targets, including deployment in another location.

GRIDSOLAR—BOOTHBAY

Central Maine Power (CMP), in a 2008 rate case filing with the Maine Public Utilities Commission (MPUC), originally proposed a 300-mile, $1.5 billion transmission upgrade for the state involving multiple transmission lines and high voltage substations to help address reliability concerns resulting from forecasted increases in peak load conditions on the grid. GridSolar intervened, arguing that these load forecasts were too high. The company stated that the $1.5 billion upgrade was needed for only a limited number of peak-load hours. After negotiation and discussion, MPUC accepted a settlement in which a large portion of CMP's proposed, traditional transmission solution would be built, but two areas of the state would

FIGURE 5: PROJECT AREA, BOOTHBAY PENINSULA



Radial nature of electric service and local distribution circuits on the Boothbay peninsula defines the electric region for the Pilot Project—Total Peak Load—approx. 30 MW.

Source: GridSolar, 2018.

28 In this case, the customer had the ability to self-direct a program rather than pay an EE surcharge. The customer decided to opt for the self-direct program.

be carved out for GridSolar to develop NWAs to address grid reliability issues.

GridSolar implemented its pilot project, which included a 500 kW, 3 MWh Convergent-supplied battery energy storage system (BESS), 250 kW of Ice Energy's thermal storage units, a 500 kW diesel-fueled back-up generator, EE commercial lighting, and rooftop solar PV systems. A total of 1.85 MW was deployed between 2013 and early 2015.

Outcome: The project demonstrated reliability benefits comparable to a transmission line; however, the project ended in 2018 because electric load growth did not materialize as originally forecasted. Maine ratepayers saved over $12 million compared to a stranded transmission asset that turned out was not needed.

NATIONAL GRID—OLD FORGE NWA

National Grid's Old Forge project is currently still in development. It seeks to improve the reliability on a radial, 46 kV sub-transmission line that feeds five substations in three New York counties. National Grid issued an RFP in early 2017 that was open to all vendors and DER technologies. Eight out of nine proposals included a BESS technology.

The utility is applying a BCA tool to short list proposals. A final decision is anticipated in Q1 2019. This project presents an opportunity to improve the Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Frequency Index (SAIFI) reliability scores for the 7,700 residential and C&I customers in the area. The project will create a microgrid connected to the primary utility grid for the majority of annual hours, but will sectionalize a fault and pick up impacted customers during an outage. The primary challenge is getting proposed projects to meet BCA testing requirements and create a project with a benefit-cost ratio (BCR) greater than 1.0.

Outcome: The Old Forge project is still in the early phases of procurement. Results will be available later in the project timeline.

NATIONAL GRID—TIVERTON NWA PILOT

National Grid designed the Tiverton NWA Pilot to serve the communities of Tiverton and Little Compton, Rhode Island. The Rhode Island System Reliability Procurement (SRP) 2012 Plan filing initiated the project, seeking to defer a $2.9 million, six-year feeder project with expectations of cumulatively meeting a 1 MW goal. This project also sought to test whether geographically-targeted EE and DR could defer the needs for a new substation feeder upgrade serving 5,200 customers.

DemandLink, the former brand name for National Grid's load curtailment program, was a major component of the Tiverton NWA Pilot and was part and parcel of National Grid's first forays into a customer-driven DR program. ConnectedSolutions is the successor DR program to DemandLink. The Tiverton NWA Pilot itself was the first in Rhode Island, as well.

The six-year project began in 2012 and ended in December 2017. It employed a variety of marketing tactics to refresh messaging and engage new participants. City managers also played a large role in reaching out to the community and engaging local citizens to understand the need for the project and its benefits. On-site auditors from RISE Engineering helped with door-to-door implementation and EE installations. The program included EE and a variety of DR resources, such as Wi-Fi thermostats, heat pump water heaters, and window air conditioners.

Outcome: In conjunction with other projects, the Tiverton NWA Pilot deferred the $2.9 million feeder project over the five years. However, the project was not able to fully realize the 1 MW of 2017 summer load reduction goal. The effort has remained cost-effective over its life, with a benefit-cost ratio of 1.40, as noted in Table 4. Each year also proved to be cost-effective aside from 2018, which had been previously designated as the final, post-pilot evaluation for those related costs only. Despite the unrealized load reduction, the substation upgrade was further deferred due

TABLE 4: SUMMARY OF COST EFFECTIVENESS FOR THE TIVERTON NWA PILOT PROJECT

SYSTEM RELIABILITY PROCUREMENT (SRP) — TIVERTON/LITTLE COMPTON SUMMARY OF COST EFFECTIVENESS ($000)								
	2012	2013	2014	2015	2016	2017	2018	OVERALL
BENEFITS	**$179.0**	**$1,325.4**	**$1,033.3**	**$1,281.1**	**$687.7**	**$568.0**	**$0.0**	**$5,074.6**
FOCUSED ENERGY EFFICIENCY BENEFITS*	$90.2	$1,015.1	$716.7	$1,024.8	$435.0	$66.94	$0.0	$3,348.7
SRP ENERGY EFFICIENCY BENEFITS**	$88.8	$310.4	$136.8	$78.0	$88.1	$341.6	$0.0	$1,043.7
DEMAND REDUCTION BENEFITS***	$0.0	$0.0	$5.6	$6.8	$5.3	$11.3	$0.0	$28.9
DEFERRAL BENEFITS†	$0.0	$0.0	$174.2	$171.5	$159.4	$148.2	$0.0	$635.3
COSTS	**$133.4**	**$672.4**	**$569.3**	**$1,029.4**	**$611.1**	**$510.9**	**$90.8**	**$3,617.4**
FOCUSED ENERGY EFFICIENCY COSTS††	$46.6	$331.1	$195.8	$529.3	$280.1	$281.3	$0.0	$1,664.1
SYSTEM RELIABILITY PROCUREMENT COSTS†††, Δ	$86.8	$341.3	$373.5	$500.2	$331.0	$229.6	$90.8	$1,953.3
BENEFIT/COST RATIO	**1.34**	**1.97**	**1.81**	**1.24**	**1.13**	**1.11**	**-**	**1.40**

Notes:

* Focused EE benefits in each year include the NPV (over the life of these measures) of all total resource cost (TRC) benefits associated with EE measures installed in that year that are being focused to the Tiverton/Little Compton area.

** SRP EE benefits include all TRC benefits associated with EE measures in each year that would have been installed as part of the statewide EE programs.

*** DR benefits represent the energy and capacity benefits associated with the demand reduction events projected to occur in each year.

† Deferral benefits are the net present value benefits associated with deferring the wires project (substation upgrade) for a given year in $2014.

†† EE costs include PP&A, Marketing, STAT, Incentives, Evaluation and Participant Costs associated with statewide levels of EE that have been focused to the Tiverton/Little Compton area. For the purposes of this analysis, they are derived from the planned ¢/Lifetime kWh in Attachment 5, Table E-5 of each year's EEPP in the SF EnergyWise and Small Business Direct Install program. These are the programs through which measures in the SRP pilot will be offered.

††† SRP costs represent the SRPP budget which is separate from the statewide EEPP budget, as well as SRP participant costs. The SRP budget includes PP&A, Marketing, Incentives, STAT and Evaluation.

Δ All costs and benefits are in $current year except for the deferral benefits.

2012-2017 numbers have been updated to reflect year-end data. 2018 numbers reflect year-end projections.

Source: National Grid (The Narragansett Electric Company), System Reliability Procurement 2019 Report, October 2018.

to slower than expected load growth and cooler summer temperatures in 2017.

SCE—DISTRIBUTION ENERGY STORAGE INTEGRATION (DESI) 1

SCE's DESI 1 project sought to defer a distribution upgrade through circuit load management with the deployment of a front-of-the-meter, grid-interactive battery storage system. This BESS was maintained by a third-party, located in an extremely compact customer location, and owned and operated by the utility as a grid asset. This project has been in operation for three years to date. The BESS is connected to the Scarlet 12 kV distribution circuit serving various C&I customers in the City of Orange. One customer served in this area has manufacturing processes that can add several MWs of load during on-peak periods, which potentially can cause the circuit to exceed its planned loading limit (PLL).

SCE procured DESI 1 through a competitive bidding process and selected a compact, lithium-ion BESS to allow for installation within a 1,600 square-foot easement at the customer's industrial facility. The project footprint also included 12 kV switchgear, a transformer, a power conversion system, an energy storage enclosure, and communications cabinet. The BESS is primarily designed to monitor the Scarlet 12 kV distribution circuit phase current and discharge as needed to prevent the current from exceeding the PLL.

Outcome: The DESI 1 team noted the project has "successfully dispatched multiple times to keep the circuit load from exceeding the limits and met its original objective." The BESS is capable of operating in other control modes, including reactive power dispatch for voltage regulation. SCE has used the system to validate distribution circuit voltage models and demonstrate reactive power capabilities.

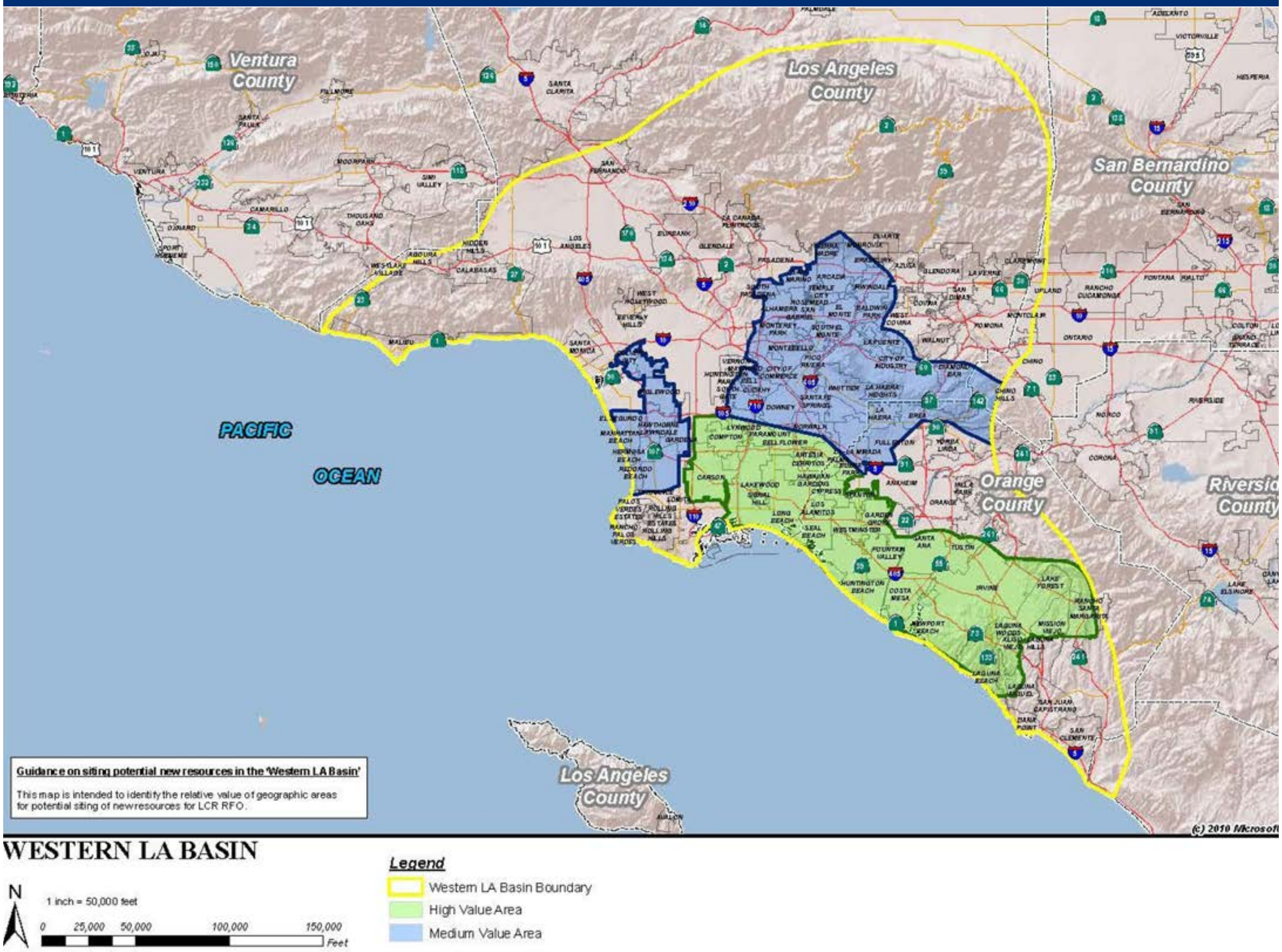
SCE—DISTRIBUTED ENERGY STORAGE VIRTUAL POWER PLANT (VPP)

Stem's Distributed Energy Storage Virtual Power Plant is one of the first, large-scale deployments of customer-sited resources for a utility. Its size demonstrates how NWAs have the potential to provide fast, reliable, and flexible resources to respond to localized grid capacity needs. In 2013, the CPUC authorized SCE to procure between 1,400 and 1,800 MW of electrical capacity in the Western Los Angeles local reliability sub-area by 2021 to meet long-term local capacity requirements (LCR). This initiative was a result of the closure of the San Onofre Nuclear Generating Station and anticipated retirement of natural gas plants in Southern California. The CPUC also directed that at least 150 MW of "preferred resources," such as efficiency, distributed solar, or energy storage resources, must be procured.

Through a competitive solicitation process, SCE contracted Stem to build and operate an 85 MW virtual power plant (VPP) consisting of battery energy storage systems to contribute flexible capacity for 10 years. In SCE and Stem's agreement, SCE has dispatch rights to capacity. This project also leverages Stem's artificial intelligence (AI) platform, Athena, to control and dispatch resources on a repeatable, real-time, day-ahead and targeted geographic basis. The VPP serves as a firm, on-call dispatchable, peak-capacity resource to help balance the grid during peak times. Over 100 systems are participating in the VPP, and many dozens more in the installation phase. Customers are offered a long-term contract with fixed monthly subscription payments, the aim being realization of automated savings worth two to three times the payment. Customers have reported satisfaction with the lack of manual effort or interference needed in operation.

Outcome: Stem dispatched distributed storage system capacity more than two dozen times in 2017, often during hours when the sun had set, which meant that distributed generation could not be leveraged to generate electricity to offset the increasing evening load. This project showed that distributed storage assets are reliable, fatigueless, quickly dispatchable, and can play an important role in complementing other energy resources to meet customer and grid needs.

FIGURE 6: SITING LOCATION MAP FOR CONSTRAINED AREA, WESTERN LOS ANGELES BASIN.



Source: Southern California Edison, 2018.

Key Insights and Challenges

With interest in and development of NWAs still in early stages, standards for procurement and business models for implementing these projects are lacking.[29] Wood Mackenzie (formerly GTM Research) estimates more than 100 NWA projects are in various stages of planning today, accounting for over three-quarters of total planned and completed NWA capacity in the U.S.[30] A smaller subset of NWA projects has moved into implementation (i.e. program recruitment, technology deployment), and an even smaller set of projects has been fully implemented.

This section provides an overview of the lessons utilities and project developers have learned in NWA planning, sourcing, and project implementation. While many projects provided lessons specific to their proposed solutions and T&D challenges, Table 5 provides a concise summary of common lessons regarding planning and sourcing in the field, as well as project and technology-specific implementation.

TABLE 5: SUMMARY OF KEY INSIGHTS AND CHALLENGES

PLANNING AND SOURCING	IMPLEMENTATION	
	PROJECT IMPLEMENTATION	TECHNOLOGY-SPECIFIC IMPLEMENTATION
Open and technology-agnostic approaches can help with project success	Plan for internal development	Launching energy efficiency first allows longer lead times for other DER solutions
Procurement processes and bidding responses require more time than originally anticipated	Community outreach helps overall reception and likelihood of project success	Demand response encompasses a wide range of technologies and was met with varying levels of success across six case studies
Uncertainty of load growth is a challenge for utilities but a strength for NWAs	Recruitment and customer engagement requires a multipronged approach	Energy storage implementation has its share of obstacles, including: siting, reliability requirements, interconnection, and system impact challenges. These challenges are largely due to the nascency of storage technologies
Know as much about your service territory as possible to inform program recruitment		
Utilities often use a benefit-to-cost assessment to evaluate NWA opportunities		

Source: SEPA, PLMA, and E4TheFuture, 2018.

29 UtilityDive, Non-Wires Alternatives: What's up next in utility business model evolution, 2017. Available at: https://www.utilitydive.com/news/non-wires-alternatives-whats-up-next-in-utility-business-model-evolution/446933/.

30 Greentech Media, A Snapshot of the US Gigawatt-Scale Non-Wires Alternatives Market, August 2017. Available at: https://www.greentechmedia.com/articles/read/gtm-research-non-wires-alternatives-market#gs.lytvWGw.

PLANNING AND SOURCING

Open and technology-agnostic approaches help with project success. Overall, program managers[31] that have achieved the most success tend to have an open approach to solutions. In the case of Con Edison's BQDM project, "a general request for information (RFI) in the beginning helped identify the types of solutions that could be implemented to solve a load-relief need." The Con Edison team found that the initial RFI widened their understanding of how different technologies fit together. As a result, Con Edison adopted a portfolio approach that was able to attract enough types of baseload resources so that they could manage not only the peak load, but the overall substation load profile. Through its Peak Perks program, Central Hudson found that taking a technology-agnostic and open approach revealed opportunities the utility had not previously considered.

> *"[We] used [our] procurement process to ask what the market could bring for innovative technology, quantified the need, and selected the solution that was best fit from both an operational and cost standpoint."—Central Hudson*

> *"One solution provider who responded to the RFI worked with us to adopt the installation of fuel cells at customer locations—an unanticipated program benefit as this was not a solution being considered at the beginning of the program."—Con Edison*

Similarly, the most successful projects approached program design without preconceived notions. Con Edison's standard proposal template, developed after the initial RFI, allows for consistent evaluation of resource solutions on a line-by-line basis to help build out its portfolio of solutions.

Build in more time for procurement processes and bidding responses. Based on feedback from project implementers, and the case studies in this research effort, NWAs require early planning. DER providers also need the ample lead time to provide commercially viable solutions.[32]

For a number of NWA projects where battery storage and other evolving resources were under consideration, project managers suggested allowing more time for bidders to respond, and potentially allowing these resources the ability to participate in the project one or two years after the start date (as interconnection studies can often take up to two years to complete). BPA suggests starting the planning process and engaging stakeholders early in order to get alignment on the problem statement, budget, potential resources, and schedule and implementation plans, as they found developing and issuing a Request for Offer (RFO) took longer than expected.

> *"Background research on battery storage technology and project planning should be done prior to issuing a contract. It should be expected that some details will be missing in the plan and last minute adjustments to the solution or site will be likely required during commissioning."—APS*

> *"[National Grid] is constantly learning from each NWA RFP, and has tweaked its RFP format to allow market participants to streamline their offerings in terms of pricing and technology. This is to eliminate confusion for all stakeholders in the big process." —National Grid*

Uncertainty of load growth is a challenge for utilities, but a strength for NWAs. For a number of the case studies in this report, forecasts of high load growth contributed to the original identification of the need for infrastructure upgrades, and thus, NWAs. In cases such as Boothbay and Swartz Creek, projected load growth did not materialize and NWAs provided the added benefit of avoiding stranded costs and deferring expensive infrastructure upgrades. BPA found that analysis of NWA opportunities helped improve earlier load

31 The term "program manager" refers generally to the entity managing the NWA project. In most cases it is the utility, but in other cases, such as the Boothbay project, it is a third party.

32 ICF, Procuring Distribution Non Wires Alternatives: Practical Lessons from the Bleeding Edge, 2017.

forecasts. In some cases, closer examination of NWA opportunities resulted in realizations that neither wires nor NWAs were needed.

> *"Anticipated load growth at the substation did not materialize, and forecasts need to incorporate the potential for load shift from another substation." —Consumers Energy*

> *"The [Boothbay] project was [online and] terminated because electric load growth did not materialize as the utility originally forecasted."—GridSolar*

Know your service territory (to inform customer recruitment). As project managers ran into challenges during the recruitment and implementation phases of their NWAs, many wished they had a deeper understanding of the demographic variations in their service territories earlier. A greater understanding of customer potential to participate in DR and EE programs would have better informed the initial planning phases of the project.

In cases where program managers were recruiting customers for DR and EE programs, many brought up the need for project teams to have a deep understanding of the divergent demographics of their service territory. Doing so helps to set reasonable recruitment targets and takes into account demographic variances. For example, Central Hudson's Peak Perks program found that in some areas, less than 10% of homes had air conditioning, much less than the average throughout its service territory.

> *"Recruitment of commercial and industrial customers has been challenging because there are only 300 [customers], mostly small businesses in the area, with economic limitations and some inflexible load profiles."—Consumers Energy*

For additional insights, see the discussion on recruitment and customer engagement below.

Benefit to cost assessments were used to evaluate NWAs. Utilities often use a benefit-to-cost assessment to evaluate NWA and other design options in order to determine the least-cost alternative for consumers. In these cases, safety, reliability, customer experience and affordability are seen as foundational pillars for decisions on NWA options.

In 2016, the New York Public Service Commission directed the Joint Utilities of New York, which includes Con Edison, Central Hudson, and National Grid, to develop and file Benefit-Cost Analysis (BCA) Handbooks every two years as a methodology in evaluating future utility programs and projects. The directive highlights four main benefits and costs to consider in the evaluation process, including:

- Avoided costs of bulk systems;
- Avoided distribution system infrastructure;
- Avoided costs of restoring power during outages;
- Avoided emissions and land impacts.

Each category of costs includes the price of program administration, reduced revenues from a decrease in electricity sales, and combined equipment and participation costs assumed by DER utilization.

Finally, the commission considers the annual costs to ratepayers of utility-shareholder incentives that are tied to a program or project being evaluated. Con Edison, Central Hudson, and National Grid each add in their own utility-specific assumptions when developing BCA Handbooks.

PROJECT IMPLEMENTATION

Plan for internal resource development: For many utility professionals interviewed, planning and deploying an NWA project meant entering new territory. Often they confronted a gap in internal processes. BPA did not have standardized ways to call DR and generation redispatch events and hence had to develop new triggering and forecasting tools.

SCE's DESI project did not have defined processes for building utility-owned and distribution-connected energy storage, hence the utility struggled to determine appropriate design standards. For other utilities embarking on similar journeys, project managers suggest planning and allocating more time for internal resource development in order to build the tools and gain the understanding needed to implement new technologies and processes.

Furthermore, performance risks associated with new technologies often justify the use of demonstrations and pilots to better understand performance and customer impacts, as well as explore mechanisms for prudent sharing of risks between participants.

Recruitment and customer engagement require a multipronged approach. For projects leveraging EE and DR programs, customer engagement and recruitment are key to success. Con Edison reached out to a range of customer segments through neighborhood canvassing, giveaways, hiring an implementation contractor, and working with government agencies to identify and implement EE and DR solutions. The utility also targeted small businesses, multifamily residential customers, and the commercial and industrial (C&I) sector with additional incentives—above already established targets—for energy efficiency measures, such as efficient lighting systems. Some of the efficiency upgrades were essentially free to the customer as a result.

Consumers Energy developed a multichannel marketing campaign with local groups competing to sign up customers for programs. It also launched a community project that incentivized local customers to participate. The utility also hired new staff to serve as an "Energy Ambassador" to help gather intelligence, gain customer participation, and provide line-of-sight to Consumers Energy's programs and rebates.

> *"Try several options to engage people. The program staff found it was necessary to make multiple contacts using various methods to recruit residential customers. While a direct marketing approach of in-person and postal outreach was found to be most effective, the impact of secondary electronic contacts through email marketing was noticeable."—Central Hudson*

Beyond EE and traditional DR programs, some utilities with storage-focused NWAs engaged customers in a new way. In the case of SCE's Virtual Power Plant, over 100 customer-sited storage systems were deployed and demonstrated high levels of customer satisfaction.

In this program, customers are offered a long-term contract with fixed monthly subscription payments, the aim being the realization of automated savings worth two to three times the payment. Customers have reported satisfaction, in particular with regard to the limited effort needed on their part to operate the storage systems.

> *"Stem is finding strong customer demand for energy storage services that provide energy bill savings, but also new ways to participate in the market via grid-support or other grid- and utility-facing services." —Stem*

Community outreach helped overall public reception and project success. Projects such as Con Edison's BQDM and APS's Punkin Center were successful in engaging customers through community outreach. The BQDM effort involved multiple programs requiring engagement with new vendors and large-scale customer recruitment.

Through these initiatives, the BQDM project experienced increased levels of engagement with customers and vendors, which was viewed by program staff as a measure of program success. In addition, local employers in Con Edison's territory referenced the BQDM program as a driver for new hires in the program's targeted areas.

In the Boothbay project, GridSolar found community engagement and awareness of the millions of customer dollars saved was an additional benefit of the NWA technologies.

> *"When the community gets involved, they learn to better understand the grid, how it works, what it needs, and sees the benefits once they've been implemented."—GridSolar*

For APS, public outreach and making sure local organizations were educated about the project helped the utility create a positive customer perception of the project and increase receptivity. The project's small footprint also meant the utility experienced no pushback or additional environmental concerns.

"Residents of Punkin Center liked the idea that the battery storage will increase reliability for the rural feeder and the unit has been well received."—APS

TECHNOLOGY IMPLEMENTATION

For any one technology, market maturity and customer recruitment opportunities influenced levels of success. Thus, some technologies and programs take longer to deploy than others, as discussed below.

ENERGY EFFICIENCY

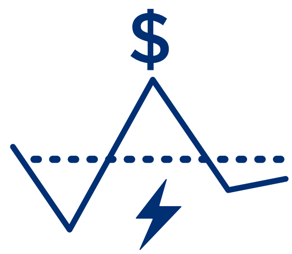
EE programs were a component in four out of the 10 NWA case examples and met with varying levels of success.

In the case of BQDM, which encompassed a large portfolio of technologies, the primary lesson learned from the field was to ramp up existing program offerings first in order to allow longer lead times for other, more complex technologies. This enabled Con Edison to build out contracting relationships with third parties for other technologies while immediately tackling load relief needs.

"Launching first with aggressively targeted marketing on existing EE program offerings bought time to allow for the longer lead times needed to introduce more complex technologies such as distributed generation."—Con Edison

Other project implementers found marketing and recruitment for EE customers to be challenging, at times requiring assistance from third parties. For the Boothbay project, GridSolar brought in Efficiency Maine to help with recruitment and installation of EE measures.

"Passive NWAs, such as EE, can be challenging to market and require a third-party implementer to deliver the service, which is difficult to deliver through the bid process."—GridSolar



DEMAND RESPONSE

DR may encompass a number of technologies and programs, such as thermostats, water heaters, and window air conditioning (AC) units. Seven out of the 10 NWA case examples included DR in their solutions, and provided insights from their efforts implementing these programs.

BPA's SOA project combines generation redispatch with a large end-user providing DR capacity. BPA noted that "relying on a single DR resource can present a challenge as the resource may not be available in the requested event window. Aggregation and oversubscription of DR resources may be a preferred option to reduce the risk of resource unavailability."

National Grid's Tiverton NWA Pilot project found that thermostats and heat pump water heaters were effective in achieving kW demand reduction. The project team also tried to recruit customers to use smart plugs for AC cycling on window units. However, this approach proved ineffective; customers typically did not use the smart plugs and instead continued running AC units when load reductions were needed.

SCE's Virtual Power Plant is an example of the industry's movement toward leveraging customer-sited energy storage systems to provide demand response. As previously noted, the Virtual Power Plant included more than 100 customer-sited electric storage systems that were dispatched during DR events.

Other DR programs, such as thermostat and behavioral programs, can affect customer comfort

TABLE 6: ENERGY EFFICIENCY AND DEMAND RESPONSE: LESSONS LEARNED

ENERGY EFFICIENCY	DEMAND RESPONSE
▪ Utilities should launch existing program offerings first in order to allow longer lead times for other complex technologies. ▪ Multipronged marketing and recruitment efforts yielded greater program success. ▪ Bringing in third-party implementers can help market and recruit customers.	▪ Aggregation and oversubscription of DR resources cuts the risk of resource unavailability that may occur if an NWA relies on a single, large DR asset. ▪ Program success varied depending on the technologies (e.g., central AC and heat pump water heaters proved more successful than window AC units with smart plugs in the Tiverton NWA Pilot) and customer recruitment opportunities. ▪ Usage of non-traditional forms of DR is rising. In the case of SCE's VPP, energy storage systems were leveraged as a new form of DR.

Source: SEPA, PLMA, and E4TheFuture, 2018.

by disrupting typical energy usage or changing the temperature in a home. When these programs call DR events too frequently, customers may feel event "fatigue" and opt out of participation over time.

SCE's Virtual Power Plant, which combined customer-sited storage with automated artificial intelligence software, was found to be "fatigueless" on a highly repeatable basis. Events can be called multiple times a day, and the storage systems respond quickly and predictably.

> *"The Virtual Power Plant's performance is showing that distributed storage assets are consistently reliable, fatigueless, and fast-dispatchable assets year-round on both a day-ahead and 'day of' call basis, in contrast to traditional DR performance." —SCE*

ENERGY STORAGE

Energy storage was a component of, or the full solution for, over half of the case studies examined in this report. The flexible capabilities of storage and the decline in costs for the technology have helped increase opportunities for its cost-competitive use in NWAs.

However, at the same time a significant number of implementation challenges specific to energy storage emerged. Simply put, the technology is still nascent, and storage-friendly procedures need to be developed and improved. As the energy storage market matures, the lessons learned from first movers, such as APS, will be available for others to learn from. With this in mind, if utilities do not have procedures in place for a new technology, then the time needed for internal development should be factored into planning.

The various challenges faced in these case studies are presented in Table 7.

> *"Do as much planning and background research (to understand the solution technology) as possible before issuing a contract; apply the BESS solution on a weak feeder; and realize that last-minute adjustments to the solution or site are likely to be required during commissioning."—APS*

LEVERAGING MULTIPLE VALUE STREAMS FOR STORAGE

Battery storage is flexible in that today's lithium-ion battery energy storage systems have a range of capabilities, giving these assets the potential to provide a number of different services and generate more than one value stream. Potential value streams may not always align with local system needs, however.

While projects such as SCE's Virtual Power Plant demonstrate opportunities to use advanced analytics to leverage multiple storage value streams, broader industry concerns remain about double counting of battery energy storage services—crediting storage for both renewable generation and storage-distribution capacity, for example.

> *"Take a year-round, holistic view to planning and collaborate with power services to identify a longer-term, agency-wide business case for energy storage. It was hard to make the math work for return on investment on a two-year energy storage demonstration. In order to compare energy storage to other assets, BPA would have needed more time and information."—BPA*

TABLE 7: ENERGY STORAGE—IMPLEMENTATION CHALLENGES	
LOCATION	The process for identifying and permitting locations for energy storage projects can be time-consuming and require patience and persistence. As SCE stated, it's all about "location, location, location." Permitting for projects is especially difficult in urban settings where land acquisition can often increase the timeline for conception to implementation from one year to two or three years, or more. For its DESI 1 project, SCE encountered difficulties finding a site with appropriate characteristics (e.g., zoning, interconnection capacity, friendly neighbors, no existing environmental concerns, workable existing above- and below-ground structures), as well as space for construction laydown and interconnection facilities. Fortunately, SCE was able to arrange to locate the BESS on an industrial customer's property.

RELIABILITY	National Grid's Old Forge project and APS's Punkin Center both faced challenges incorporating energy storage onto the T&D system for reliability purposes.
	▪ At Old Forge, National Grid is finding challenges in overcoming the limited runtime of batteries to support unpredictable outages.
	▪ APS found it could not make a straightforward comparison between the reliability profiles of traditional wires upgrades and battery storage. To meet internal reliability goals (which added to project costs), the utility had to consider:
	  ▪ Layers of redundancy;
	  ▪ Back-up plans;
	  ▪ Battery oversizing;
	  ▪ Battery operational limits (including state of charge and number of cycles).

INTERCONNECTION	Interconnection challenges were the most common implementation obstacles across all energy storage solutions. ▪ SCE's Virtual Power Plant had to streamline interconnection of customer-sited storage without sacrificing important engineering reviews. ▪ The Boothbay project struggled with securing interconnection agreements for storage, as well as other NWA resources. The project developers ultimately worked with Central Maine Power to provide interconnection agreements for the two NWA resources. Under the agreements, these resources would only be dispatched during peak-load periods, when circuit loadings were at their highest levels. ▪ At National Grid's Old Forge project, interconnection costs become a significant barrier for technology requiring multiple points of common coupling. ▪ For many early implementers, the lack of defined standards can be an obstacle.
DIFFERENT PERMITTING AND INSPECTION PROCESSES	Yet another challenge for the DESI 1 project was navigating the different state and local permitting and inspection processes. The project was able to get an exemption from local discretionary permits and inspection requirements per CPUC's General Order 131D. SCE, however, was still required to file ministerial permits by the local authority having jurisdiction and is required to meet safety and design requirements approved by the CPUC.

Source: SEPA, PLMA, and E4TheFuture, 2018.

OTHER TECHNOLOGY-SPECIFIC LESSONS LEARNED

In the case of the Boothbay project, the characteristics of Central Maine Power's peak load aligned well with solar PV generation in the region. Solar was therefore considered a passive NWA solution that provided locational benefits to the system.

"Since they were located downstream of the key constraint on the grid, [the PV systems] had the effect of lowering the amount of energy required to be imported into the region by providing additional capacity on the constrained transmission line."
—GridSolar

See Appendix for additional lessons learned specific to technologies.

NWA PROJECT FINDINGS

The majority of projects examined in this report were successful in helping to delay or permanently defer infrastructure upgrades. However, the majority of projects discussed here are not complete, and a few were still in the procurement stage as we prepared for publication. Further, additional data regarding results and final outcomes for active projects may not be available until a later stage in their life cycles.

Specific outcomes of the 10 case studies are detailed in Table 8; a summary follows below.

- **Flexibility:** The flexibility of NWAs means that utilities can implement these projects in phases as load grows, as occurred in projects such as Boothbay and BQDM. Incremental implementation also helps avoid large upfront costs and the needs to oversize projects to match potential load growth. Projects like APS's Punkin Center were designed with the capability to add energy storage capacity as needs arise over the next five to 10 years.
- **Reliability:** As mentioned earlier, implementing NWA projects and meeting reliability requirements are achievable goals. Specific projects such as Punkin Center and Boothbay focused largely on reliability. GridSolar noted that its project "provided comparable reliability at lower cost than the transmission construction project." While multiple layers of redundancy[33] were needed to deploy APS's BESS system at Punkin Center, the project's reliability requirements were also successfully met.
- **Cost Savings:** While cost information was not readily available for many of the case studies, projects such as SOA, Boothbay, BQDM, and the Tiverton NWA Pilot reported significant cost savings (detailed in Table 8). In a handful of cases, NWAs also substantially reduced potential stranded costs that could have resulted from investing in unnecessary infrastructure upgrades and then finding that forecasted load growth did not materialize.
- **New approaches to revenue and incentives are needed:** The traditional utility compensation model of obtaining a fixed rate of return on traditional capital investments served as a hurdle for many projects (see sidebar on p. 15). As noted by Frank Brown at BPA, equitable cost allocation is needed for NWAs, perhaps through performance-based regulation to incentivize congestion-cost management for T&D owners.[34]

  It should be acknowledged that such changes, in many cases, will require an update of

33 In the case of APS, "multiple layers or redundancy" included having spares of critical, long lead-time items such as Vista switchgear and the 21 kV/420 V transformer kept on site. The site was configured to connect a diesel generator in case of an extended battery storage system outage, and APS contracted with a local diesel-generator provider to deliver a 2 MW generator within a few hours of notice to the site.

34 Frank Brown, BPA and Non-Wires Work: Some highlights from the past 30 years, Pacific Northwest Demand Response Project, June 2018.

the traditional utility compact and revenue recovery model while maintaining the utility's commitment to providing customers with safe, reliable, and affordable choices.

In Central Hudson's Peak Perks program, the utility collaborated with regulators to create a unique, incentive-based compensation model that ensured the program is financially beneficial for both the utility and customers. This project deferred new infrastructure projects in three zones in Central Hudson's service territory. Through this incentive-based model, 70% of benefits go to customers through rate moderation, and 30% of benefits go to the utility as an incentive for running the program effectively.

Overall, NWAs are an opportunity to extend the life of existing assets, and can be a cost-effective solution when building T&D infrastructure is costly or geographically challenging. Through their recent NWA projects, BPA has found NWA analysis can bring "fresh eyes" into the transmission planning process. In BPA's region, NWAs can provide an opportunity to "extend the use of existing assets for many years of short-term peaks and slow load growth."[35]

TABLE 8: SUMMARY FINDINGS FOR NWA CASE STUDIES

APS—PUNKIN CENTER	▪ The Punkin Center project was designed to defer system upgrades for a decade or longer. If load growth materializes as originally forecasted by the utility, this project has the potential to provide long-term deferment of the wires investment. ▪ Looking towards the future, after formalizing the process for analyzing their feeders to consider battery vs. rebuild, APS found they are in a good position to consider other projects in the 2020 timeframe. *"Punkin Center battery project was not a science project. The project reframed the discussion on the options to best serve customers in hard-to-reach rural areas."—APS*
BPA—SOUTH OF ALLSTON (SOA)	▪ The SOA project met its original objective of "demonstrating that flows across SOA can be reduced during summer peak periods through bilateral contracts." ▪ The cost of the originally proposed South of Allston 500 kV line was $1.1 billion. 2017-2018 SOA project expenses fell within the $5 million per year transmission budget amount. BPA plans to leverage lessons learned from this effort to inform future NWA plans.
GRIDSOLAR—BOOTHBAY	▪ Load growth did not materialize as forecasted originally. Boothbay therefore ended, but it helped avoid stranded costs from the unneeded transmission project. ▪ Costs for the project were estimated at around $6 million. Maine ratepayers saved over $12 million in present value terms compared to the transmission alternative.
CONSUMERS ENERGY—SWARTZ CREEK ENERGY SAVERS CLUB	▪ Consumers Energy's goal was to reduce load requirements below 80% of maximum summer capacity. While increased program participation is helping the project reduce demand, project participation goals proved to be too high and have not yet been met. The project is still active, and the team is currently exploring additional opportunities to meet targets. ▪ The original goal was to defer $1.1 million of infrastructure construction costs. Load growth did not materialize as forecasted, thus construction was not needed.
CENTRAL HUDSON—PEAK PERKS	▪ Central Hudson achieved more than 30% participation of eligible customers within the targeted zone (Fishkill) with the most capacity need. ▪ The utility exceeded the total first-year MW target for all three zones, achieving 5.9 MW of load reduction compared to the target of 5.3 MW.

35 Bonneville Power Administration, 2018.

TABLE 8: SUMMARY FINDINGS FOR NWA CASE STUDIES, CONTINUED	
CON EDISON—BQDM	▪ The BQDM program helped to meet objectives by implementing both traditional and non-traditional customer-side and utility-side solutions. ▪ Savings have successfully delayed the buildout of a new substation with an NYPSC-approved, $200 million budget beyond the initial load relief projections. ▪ Con Edison is looking for additional load reductions to delay the buildout further with a recently announced program extension.
NATIONAL GRID—OLD FORGE	▪ The Old Forge project is still in the early phases of procurement. Results will be available later in the project timeline.
NATIONAL GRID—TIVERTON NWA PILOT	▪ While total deferment of National Grid's substation was not fully achieved (a 1 MW load-offset goal was set), the project contributed to successful deferral of a $2.9 million feeder project. The overall cost of the Tiverton NWA Pilot is calculated to be approximately $3.6 million.[36] ▪ In response to the Tiverton NWA Pilot, National Grid has proposed another NWA project called the Tiverton-Little Compton NWA Project (TLC NWA Project) in their 2019 SRP Report that would operate through the summer of 2022. This will kick off with an RFP to be released in 2019 to identify cost-effective, market-based solutions that further defer the Tiverton Substation upgrade. National Grid is thus taking a more RFP-based approach to NWAs that is similar to others in the region. *"The holistic portfolio approach satisfied the need; the substation upgrade continues to be deferred. National Grid acknowledges there may still need to be an upgrade in the future." —National Grid*
SCE—DESI 1	▪ The DESI 1 project has "successfully dispatched multiple times to keep the circuit load from exceeding the limits and met its original objective." ▪ The team found the BESS is capable of other control modes. This includes reactive power dispatch for voltage regulation. *"SCE used the system to validate distribution circuit voltage models and demonstrated the ability of a BESS to use reactive power to improve voltage on the circuit."—SCE*
SCE—VIRTUAL POWER PLANT	▪ The VPP fleet of distributed storage systems was dispatched over two dozen times throughout 2017, often during hours when the state's solar generation rapidly decreased and as evening load increased. The project contributed to meeting critical, peak capacity during unprecedented 2017 summer and fall heat waves. *"[The Virtual Power Plant] project demonstrates how SCE has successfully created other opportunities for its customers to lower their energy bills and to contribute in new ways to a reliable, modernized grid."—SCE*

Source: SEPA, PLMA, and E4TheFuture, 2018.

36 National Grid - 2019 System Reliability Procurement Report, Table S-2, October, 2018. Available at: http://www.ripuc.org/eventsactions/docket/4889page.htm.

Conclusion

The handful of utility project case studies chosen for this report have indicated they are interested in looking for additional NWA opportunities — signaling a growing acceptance of non-traditional solutions for utility system T&D planning. For example, ConEd announced a program extension for BQDM, and the utility is looking for additional load reductions to delay and possibly permanently defer a new substation. ConEd is also evaluating opportunities for achieving additional load reductions in 2019 and 2020 through continued collaboration with utility partners and customers. APS also signaled interest in examining more NWA projects.

As electrification begins to spread across the country and displace natural gas or conventional transportation fuels, more opportunities for load growth, as well as greater uncertainty will arise. Alternatives to traditional transmission and distribution upgrades (e.g., substations, transformers, wires) will become even more critical for addressing customer concerns about the amount of time and cost traditional strategies may entail.

While many of the case studies in this report achieved their primary objectives, much work remains to be done to understand how DERs can best provide alternatives to traditional infrastructure upgrades. New incentives, regulations, and changes in traditional utility business models will be needed to expand NWAs. Stakeholder groups, such as the District of Columbia's Modernizing the Energy Delivery System for Increased Sustainability (MEDSIS), could help identify opportunities as part of a comprehensive stakeholder process, thereby facilitating some of these deeper regulatory discussions.

AREAS FOR FURTHER DISCUSSION AND RESEARCH

The insights discussed in this report provide early takeaways from a small set of NWA projects. Additional topics requiring further research and discussion include:

- **NWA sourcing:** While this report touches on sourcing methods for the 10 case studies, many stakeholders could benefit from a deeper dive into the procurement processes and screening criteria for NWAs. This information would help guide other utilities as they initiate new NWA projects and help third parties align their products and services with grid needs.[37]
- **Utility control versus ownership:** In cases like Boothbay, deciding who controls, develops and operates specific components of a project has been a point of contention. The Maine Public Utilities Commission has formally separated ownership from control. The resulting models for asset control and ownership are briefly discussed in the GridSolar case study, but additional questions and issues must be explored, including:
  - How would customers be protected if projects were completed by a third party?
  - Since commissions provide consumer protection policies for regulated assets, should customers have similar protection for third-party services?
  - What level of reliability should third party-owned systems be required to meet?
  - Should utilities in states with competitive, deregulated markets be allowed to own or operate DERs?

37 Note: The Rocky Mountain Institute (RMI) is currently tackling best practices and providing recommendations for NWA procurement. More information can be found at: https://rmi.org/our-work/electricity/.

- **Contracting:** NWAs present a new area of contracting for utilities, and benchmarks for some terms and conditions have yet to be established for technology providers and third-party owners of these projects (e.g., benchmarks around performance guarantees or liquidated damages).
- **Multiple benefits, proper counting, and allocation:** As with storage, NWAs oftentimes include investments with broad and multiple benefits for generation, distribution, and transmission, not to mention their environmental and other non-energy attributes. Figuring out how DER resources can serve more than one purpose is an issue that utilities, operators in the wholesale markets, and NWA project managers are grappling with today. The industry is still working to determine how to allow DERs to participate in multiple programs without double counting and overcommitting resources.
- **Cost analysis, allocation, and financial risks:** Opportunities exist for exploring new incentive mechanisms for NWAs as opposed to traditional rate-based cost recovery. In addition, a number of utilities are independently struggling to get projects, especially energy storage projects, to financially pencil out. Issues here include:
    - How should costs be apportioned to those receiving benefits? Stakeholders may argue that NWA costs should be socialized in cases where a project is benefiting customers who would traditionally be paying for infrastructure upgrades. Others may want to allocate costs so those not using the assets do not have to pay.
    - What cost-benefit models or equations will be needed to properly evaluate and balance cost allocations? More information on benefit-cost analyses for energy storage technology would largely benefit the public.
    - What are the rules for defining the attributes of NWA costs?
    - For NWA pilots, who bears costs of teardown at the end of the pilot? Are stranded assets created with these pilots?

NWA BENEFIT-COST ANALYSIS AND NEW INCENTIVE MODELS FOR UTILITIES

To assist with BCA of NWA projects, and for DER-related ratepayer investments more generally, the principles and cost-effectiveness screening framework set forth in the *National Standard Practice Manual* (NSPM—Edition 1) may be helpful to jurisdictions in analyzing the relevant costs and benefits of NWA projects.

While the NSPM in its first iteration focuses more specifically on BCA for energy efficiency, plans are in development to expand the NSPM in 2019 to address other DERs, including in the context of NWAs. For further information, see https://nationalefficiencyscreening.org/national-standard-practice-manual/.

- **Beneficial electrification, its impacts on the grid, and the role of NWAs:** As some of the case studies discussed here demonstrated, anticipated load growth does not always materialize. However, the electric power industry is taking notice of the possibility of significant load increases from transportation electrification and other forms of beneficial electrification in the coming years. NWAs may play a role here, as discussed in the callout box below.
- **Cybersecurity:** What cybersecurity capabilities need to be built into NWAs? What entity will develop and oversee the implementation of standards?

NWAs TO SUPPORT TRANSPORTATION ELECTRIFICATION

As transportation electrification increases capacity demands on the grid, utilities will need to determine how to cost-effectively upgrade their systems to meet these new needs. Rather than continuing to rely on traditional grid upgrades, a more effective route might be to minimize investments in grid infrastructure by leveraging the technology in the vehicles themselves and making alternative investments.

In a 2017 study published in conjunction with the Sacramento Municipal Utility District (SMUD) and Black & Veatch, SEPA looked at SMUD's projections for EV adoption in its service territory through 2030. Based on those forecasts, SMUD's costs to upgrade and replace transformers were estimated at $50-$100 million. The study recommended managed charging (also known as V1G or smart charging) as a way to mitigate those infrastructure costs.[38]

However, even with managed charging, system upgrades will still be needed, particularly for substations and transformers. Instead of traditional investments, utilities could work hand-in-hand with their customers to implement non-wires alternatives. Some possibilities here might include DER solutions such as on-site energy storage—either in front of or behind the meter—more intelligent, grid-edge software, or the use of an on-board vehicle battery with vehicle-to-grid technology. Such strategies could help avoid significant grid investments that could become stranded assets if a significant number of EVs move out of an area, another vehicle technology emerges, or another charging preference evolves within a community.

38 SEPA, SMUD, and Black & Veatch, Beyond the Meter: Planning the Distributed Energy Future, Volume II, 2017. Available at: https://sepapower.org/resource/beyond-meter-planning-distributed-energy-future-volume-ii/.

Appendix: Case Studies

Case studies are provided in this Appendix in the following order:

- Arizona Public Service (APS)—Punkin Center
- Bonneville Power Administration—South of Allston
- Central Hudson Gas & Electric—Peak Perks Targeted Demand Management Program
- Con Edison—Brooklyn Queens Demand Management Program
- Consumers Energy—Swartz Creek Energy Savers Club
- GridSolar, LLC—Boothbay Project
- National Grid—Old Forge
- National Grid—Tiverton NWA Pilot
- Southern California Edison (SCE)—Distribution Energy Storage Integration (DESI) 1
- Southern California Edison—Distributed Energy Storage Virtual Power Plant

For case study contact information or follow-up questions, please email research@sepapower.org

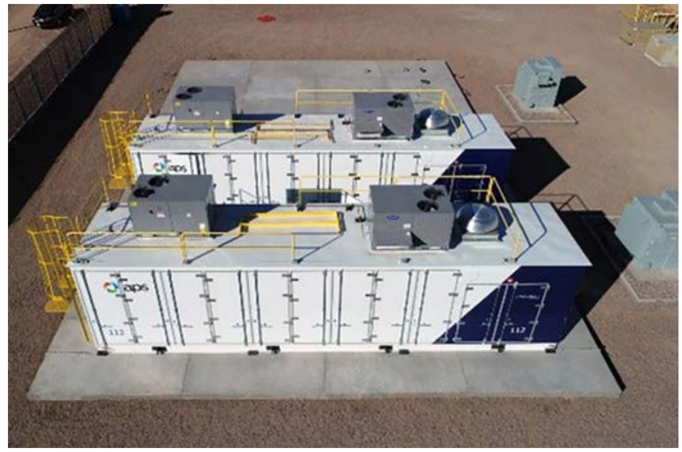
ARIZONA PUBLIC SERVICE (APS)—PUNKIN CENTER

OVERVIEW:

- **Size and Location:** 2 MW, 8 MWh in Punkin Center, Arizona (about 90 minutes Northeast of Phoenix)
- **Challenge/Opportunity:** Rural location with difficult geography and thermal conditions in both summer and winter
- **Primary Drivers:** Thermal constraint on distribution feeder and economic benefit for APS's customers
- **Technology Focus:** Electric Storage
- **Sourcing:** Direct Procurement (Competitive-bidding process)
- **Utility and Other Key Allies:** Arizona Public Service, with Fluence Energy as the battery supplier
- **Status:** Active since Q1 2018

SUMMARY:

The Arizona Public Service (APS) Punkin Center Battery Energy Storage System (BESS) Project is a BESS designed for 21 kV feeder-level peak-shaving to support the remote community of Punkin Center. This project was the least-cost option to serve the growing temperature-driven loads in the rural location. In addition to feeder-level wires capacity deferment, the BESS also counts for avoided generation capacity. APS considers the project to have been well-conceived with the objective of avoiding wires investment and generation while also finding new ways to use storage. The project has yielded lessons that will be transferable to many other locations and utilities. Due to the success of this project, APS is considering additional NWA opportunities.



Source: Arizona Public Service, 2018.

CHALLENGE AND OPPORTUNITY:

In 2016, APS's 21 kV Mazatzal distribution feeder was targeted for a rebuild due to creeping load growth in the Punkin Center area that could ultimately result in a thermal overload of the feeder. In planning and evaluating how to best address the problem, APS considered several alternatives. These included: 1) diesel gensets; 2) combined solar plus storage; 3) a battery system (BESS); and 4) a traditional line upgrade. The BESS provided the least-cost, best-fit solution overall when compared with rebuilding 17 miles of 2R[39] power lines over rough terrain.

While the primary driver in making the decision was the economic benefit to APS's customers, there were also regulatory considerations. In 2016, APS agreed to add 10 MWh of battery storage to its system as part of an Ocotillo Modernization Project stakeholder proceeding. The Punkin Center battery-storage system was one of three projects that APS built in fulfillment of that 10 MWh obligation.

Given the high level of reliability required for this project, APS had to carefully think through the battery deployment in order to provide several layers of redundancy. For example, critical spares such as an extra Vista gear and a spare 21 kV/420 V

39 2R is a type of primary cable wire size #2, wire type – ACSR, 7/1 stranded, with a max carry of 174A.

transformer are kept on-site, as these are specialty items with long procurement lead times. APS also configured the site to allow for the connection of a temporary generator to the battery site's spare transformer in the event of an extended battery outage. Additionally, APS contracted with a local diesel-genset provider for the rapid delivery of a 2 MW genset to the Punkin site within a few hours' notice, if needed.

APS also worked to develop several different means of dispatching the battery. For the primary method, APS studied historical loading on the affected feeder to come up with a routine dispatch schedule to handle most loading scenarios. The second method transmits loading information from the feeder head, where the thermal constraint is located, down to the battery through wireless communications. The final method being developed will implement local metering on the feeder outside of the battery site that will be hard-wired into the battery controller, thereby allowing continued operations in a loss-of-communications scenario.

Additional challenges were discovered in the system impact study. Given the length of the feeder, APS had previously introduced six voltage regulators that were coordinated using an Integrated Volt/VAR Control (IVVC) scheme to manage voltage. The IVVC algorithms were not designed for operation during reverse power-flow conditions. During low-load periods, the battery is large enough that a full discharge could cause reverse power flows, nullifying the feeder's voltage control scheme. To prevent reverse power flow, the local feeder metering point will also serve to manage the maximum possible dispatch at any given time until a firmware update can resolve the reverse-power flow IVVC limitation. Discovering this challenge led to changes in the IVVC software that will benefit all of the vendor's customers and allow future utilities who use the IVVC product to more easily integrate battery storage.

SOLUTION:

The initial site buildout includes a 2 MW, 8 MWh BESS that began operation in March 2018. The batteries will increase power reliability to serve the community of 600 residents, located roughly 90 minutes northeast of downtown Phoenix. The battery project is designed with the capability to add energy capacity as the need arises over the next five to 10 years.

RESULTS:

The project became commercially operational on March 8, 2018 and has been in daily operation ever since. It successfully provided feeder peak shaving during the summer of 2018 with high reliability. The project went from solicitation to operation in nine months: Ideation started in 2016, the budget was approved in late 2016, a Request for Proposals (RFP) was released in March 2017, and the contract was executed in July 2017. Construction started in December 2017, and the project was online in March 2018, within a week of the original schedule, even though it was the first non-demonstration project of its kind. Although APS does not necessarily want to repeat that timeline on another project, this accomplishment helps illustrate one of the advantages of a battery-based system over traditional wires solutions. The project is operating well and with minimal disruptions, which is a testament to lessons learned from APS's first two Li-ion battery demonstration projects, which preceded this full deployment.

If future growth matches the original load growth forecasts, this project has the potential to provide a long-term deferment of the wires investment. Having now formalized the process of analyzing the feeders to consider battery versus rebuild, APS is in a good position to consider other projects in the 2020 timeframe. APS considers battery storage to be a promising alternative in the planning toolkit, subject to ongoing performance validation in broader deployment.

KEY TAKEAWAYS AND LESSONS LEARNED:

- **Do as much planning and background research** as possible to understand the technology and solution before issuing a contract. Apply the BESS solution on a weak feeder. Realize that last minute adjustments to the solution or site are likely to be required during commissioning.
- **Consider operational aspects** of how the BESS will be charged or called before installation (e.g., Are internal controls and data requirements in place?).
- **Formalize the process of analyzing the condition and capacity of feeders** when considering battery versus upgrading or replacing power lines. Be sure to account for line losses when sizing the battery.
- **Engage the public.** APS performed proactive public outreach to ensure that local organizations were informed, and that public response to the project would be positive. Residents of Punkin Center liked that the BESS would increase reliability for the rural feeder, and the unit has been well received. It is not a straightforward process to compare the reliability of a traditional wires upgrade to the reliability of an energy storage project. Contractual obligations,[40] layers of redundancy, back-up plans, and capacity oversizing were all issues that had to be addressed to meet internal reliability goals. Without careful planning, costs can creep upwards from the original forecast.
- **This wasn't a science project.** This project reframed the discussion around how to best serve new customers in hard-to-reach rural areas.
- **Plan for the first BESS deferment effort to be difficult to implement** due to the production of new training content and the number of operations process additions and changes that will be necessary to make it successful.
- **Formalize the process of analyzing feeder upgrade work** and consider batteries as a potential solution in similar projects. Cost-effective NWA projects using energy storage are available today, and utilities should capitalize on these opportunities where possible.

TO LEARN MORE (SUPPORTING DOCUMENTATION/SOURCES):

- Punkin Center Battery Storage Video

40 Contractual obligations include real power availability and round trip efficiency obligations.

BONNEVILLE POWER ADMINISTRATION—SOUTH OF ALLSTON

OVERVIEW:

- **Size and Location:** Over 100 MW of flow relief along the I-5 Corridor in southwest Washington and northwest Oregon
- **Challenge/Opportunity:** Transmission grid constraint
- **Primary Drivers:** Internal management decision
- **Technology Focus:** 89% Generation Redispatch and 11% Demand Response
- **Sourcing:** Direct Procurement
- **Utility and other key allies:** Bonneville Power Administration
- **Status:** Active from July 2017 to September 2018

SUMMARY:

SOA was designed to validate the application of non-wires measures to mitigate summer peak flows on the SOA flowgate. The SOA Pilot ran from July 1, 2017 to September 30, 2018 and operated on a day-ahead preschedule in the summer months of July to September. The program was available only on weekdays. Weekends and North American Electric Reliability Corporation off-peak holidays were excluded. The annual SOA Pilot budget was $5 million, a total of $10 million for the two-year period.

CHALLENGE AND OPPORTUNITY:

BPA's Transmission Services organization originally proposed the I-5 Corridor Reinforcement Project (I-5 Project) in 2009 as a solution to preserve reliability, meet existing contract requirements, reduce curtailments, and serve growing demand on the transmission system. The proposed project involved construction of an 80-mile, 500-kilovolt (kV) transmission line that would cost over $1 billion.

On May 18, 2017, BPA Administrator Elliot Mainzer announced the decision not to build the I-5 Project and instead embraced "a more flexible, scalable, and economically and operationally efficient approach to managing our transmission system." The decision concluded a comprehensive, seven-year public process to determine whether building a new transmission line was the best solution to address the grid reliability issue identified along the transmission corridor.

SOLUTION:

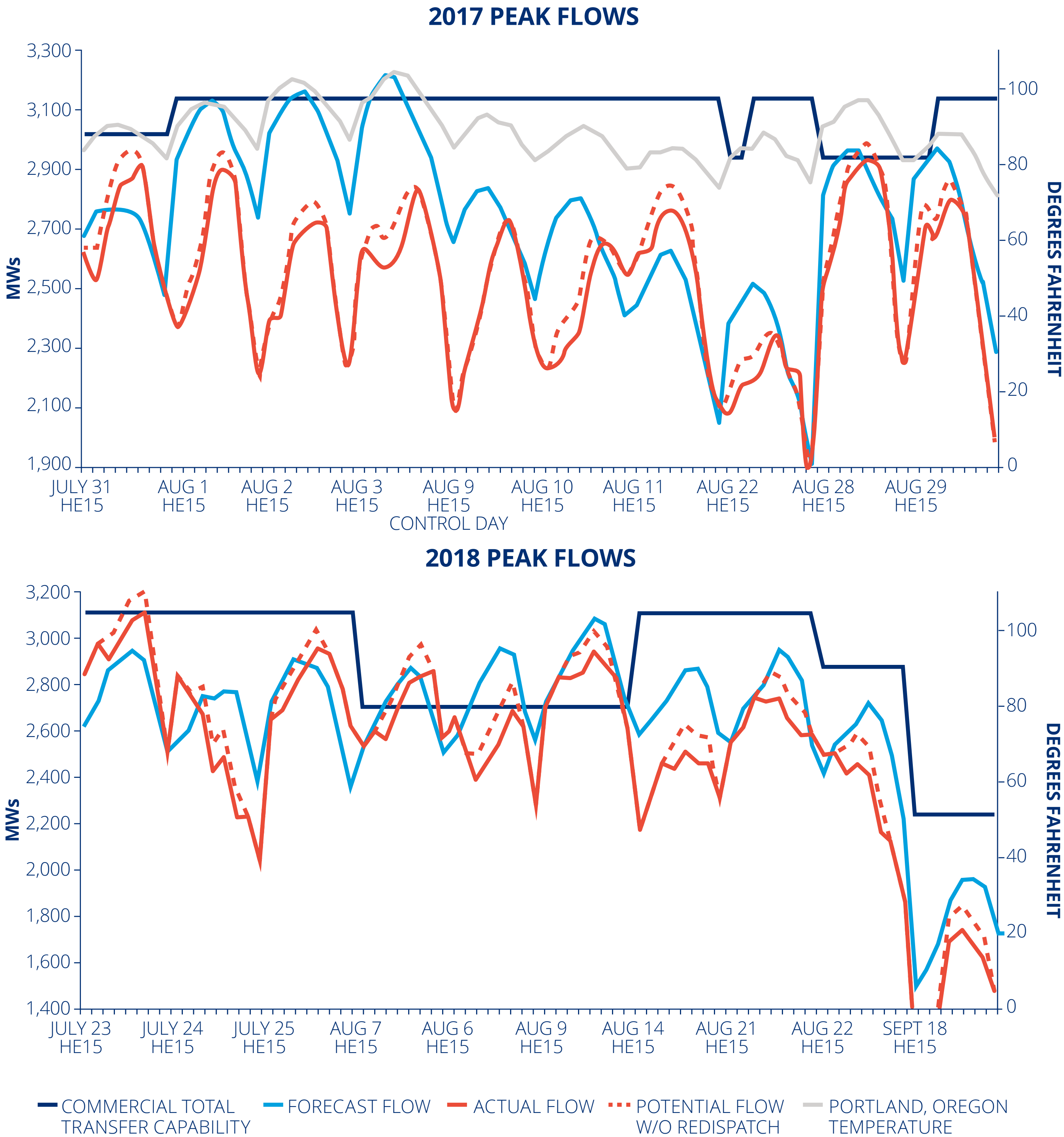
The SOA portfolio is balanced with roughly 200 MW of incremental (INC) capacity (south of the flowgate) and 200 MW of decremental (DEC) capacity (north of the flowgate). To maximize value, the total portfolio is dispatched in aggregate and yields approximately 100 MW of flowgate relief at the SOA flowgate during summer peak periods. The SOA Pilot included two types of solutions: demand response (DR) and Generation Redispatch.[41]

The key driver behind BPA's decision to acquire a portfolio of non-wires for the SOA Pilot was the risk of increasing flows across a constrained transmission path during summer peak periods. The pending decision from the BPA Administrator regarding the proposed I-5 500-kV wires project placed importance on including a solution to test the technical and operational aspects, as well as understand the cost-effectiveness of non-wire measures.

BPA released its first All Sources RFO on April 26, 2016 so as to create a competitive bidding process to acquire cost-effective, third-party supplied capacity in the form of INCs, DECs, and demand side management (DSM) load reduction for use

41 Bilateral purchases of INCs and DECs from existing commercial generators to alleviate congestion by reducing power being transmitted along a path and increasing the amount of generation closer to load.

SOUTH OF ALLSTON SUMMER 2017 AND 2018 PEAK FLOWS



Note: HE15: Hour Ending 15 (the hour from 14:00 to 15:00)

Source: Bonneville Power Administration, 2018.

in the BPA Balancing Authority Area for summer peak congestion relief at the South of Allston (SOA) flowgate. BPA developed and posted a zonal congestion map and Long-Term Power Transfer Distribution Factors (PTDF) Calculator to help interested parties locate their resource, determine which term sheet to use, and calculate potential impacts on SOA congestion relief from different Point of Receipt / Point of Delivery combinations. The market response to the RFO included a wide variety of projects, from generation dispatch, energy storage, dispatchable voltage regulation (DVR), and DSM resources. Based on a rigorous bid evaluation, BPA procured a cost-effective portfolio with approximately 45 MW of demand response and 355 MW of generation redispatch for use in the SOA Non-Wires Pilot.

The transmission path congestion analysis identified north-to-south flows, mostly from generation north of Portland that was serving a combination of local demand and exports to the Southwest. BPA had to consider flow and system balancing; the intent was to replace transmission use and identify suitable areas for generation and load reduction. This required pairing the RFO sources with precision. If generation is reduced in one place, generation has to be turned on elsewhere, i.e. the system must be balanced at all times.

RESULTS:

The preliminary results of the SOA Pilot showed that the pilot met its objective by demonstrating that SOA flows can be reduced during summer peak periods through bilateral contracts. Additionally, SOA Pilot expenses for 2017-2018 were each well within the $5 million per year transmission budget amount. Now concluded, BPA is conducting post-event analysis, which involves comparing performance results and lessons learned across summer 2017 and summer 2018 to evaluate the overall success of the SOA Pilot. BPA plans to leverage lessons learned from the SOA Pilot to inform future, longer-term non-wire program plans.

BPA purchased up to 40 hours of congestion relief per summer. BPA discovered that more hours could have been used to mitigate high SOA summer flows during both summers, but especially during summer 2017 when SOA flows were higher than normal for several days. BPA also discovered that weekends and holidays will likely need to be included in the next RFO seeking non-wires alternatives. SOA summer peak flows during the SOA Pilot event periods were lower with the NWA in effect than without it. The amount of flow gate relief does vary depending on the event day and day of system conditions, including unplanned outages, however.

KEY TAKEAWAYS AND LESSONS LEARNED:

The SOA Pilot helped to advance BPA's understanding of how to translate technical requirements into commercial terms, how to establish new performance criteria, how to use demand response to meet transmission needs, and how to develop a new flow prediction model that may not have been discovered otherwise. Other takeaways included the following:

- **Relying on a single demand response resource can present a challenge** as the resource may not always be available. Hence, it's best to evaluate each resource for its capability and deployment limits; aggregation and over-subscription may reduce the risk of unavailability.
- **The RFO took far more time and effort to stand up than expected.** Start early with project planning and engage sponsors often to get alignment on the problem statement, budget, resources, schedule, and drafted implementation plans.
- **Establish data requirements** needed to be collected and analyzed for post-event performance before the project goes live. Identify in the scoping phase what systems, data storage and analytical tools are needed to support your program. Add extra expense to your budget to cover these costs.
- **Take a year-round holistic view to planning** and collaborate with power services to identify a longer-term, agency-wide business case for

energy storage. For the All Sources RFO, it was hard to make the math work for return on investment on a two-year demonstration. Given it was single transmission use, BPA did not look at other potential uses for the asset to provide a return in non-summer months. In order to compare to other assets, BPA will need to evaluate use of the asset for other parts of the business outside of the original needs assessment.

- **Look at the whole system.** The non-wires portfolio may have been different had a holistic view of storage assets been taken (e.g., when batteries could have been used at other times or a longer contract term been negotiated, e.g., 10 or more years). With a greater understanding of the whole power and transmission system and year-round needs, BPA can understand where these assets can be deployed outside of summer peak periods.
- **Understand the market.** The peak conditions that require additional generation may cause the merchant plants to continue running anyway.
- **Understand billing system capabilities.** BPA was initially unclear on what product codes to use to account for and settle expenses associated with the SOA Pilot. BPA finance staff identified a procurement system that will book payments and charges to the standard billing system as a default, thereby avoiding unnecessary retrofitting of the billing system.
- **Plan for some internal tool development and system integration.** BPA initially had no standardized way to determine the best time to trigger SOA Pilot events. As a result, staff developed a new trigger and forecasting tool that uses ridge regression to predict day-ahead flows on the SOA.
- **Build in more response time for bidders** to respond, or consider allowing developing resources to participate one-to-two years after the start date of the new project (e.g., new generation interconnection studies can take up to two years to be completed).
- **Be prepared to revisit and renegotiate contract terms and conditions** to reflect unanticipated situations that impact the value or performance of your program. For example, BPA agreed to reimburse third-party providers for purchasing transmission for the SOA Pilot and discovered that some of this reserved transmission was mistakenly redirected for commercial purposes. The contracts did not anticipate settlement for non-compliance with transmission use.

TO LEARN MORE:

- Public to access information of the SOA project
- More information on BPA's RFO SOA project
- Attachment 1: May 17, 2017 Letter from the Administrator RE: Decision not to build the I-5 Project

CENTRAL HUDSON GAS & ELECTRIC—PEAK PERKS TARGETED DEMAND MANAGEMENT

OVERVIEW:

- **Size and Location:** 16 MW in New York State's Mid-Hudson River Valley
- **Challenge/Opportunity:** Distribution grid constraint
- **Primary Drivers:** Regulatory mandate
- **Technology Focus:** Demand response
- **Sourcing:** Customer program
- **Utility and other key allies:** Central Hudson with Itron and CPower
- **Status:** Active since 2016

SUMMARY:

Central Hudson's Peak Perks Targeted Demand Management Program was designed in conjunction with the New York Public Service Commission's REV initiative. The program seeks to defer the need for new infrastructure in three targeted zones for five to 10 years, reduce future bill pressure for customers, and create additional earnings opportunities for the utility.

CHALLENGE AND OPPORTUNITY:

Central Hudson Gas & Electric Corporation's (Central Hudson) innovative targeted demand management program, Peak Perks, was designed in conjunction with the New York Public Service Commission's Reforming the Energy Vision (REV) initiative. The REV initiative has incentivized the State of New York's utilities to leverage the targeted and coordinated deployment of distributed energy resources, such as demand response, to address problems traditionally handled by new investments in centralized generation, transmission and distribution infrastructure.

The program was designed to enable Central Hudson to defer new infrastructure in three targeted zones, reduce future bill pressure for customers, and create an additional earnings opportunity for the company. The goal was to delay infrastructure upgrades in the three areas for five to 10 years that otherwise would have been required sooner due to forecasted load growth.

SOLUTION:

The targeted DR measures were aimed at reducing summer peaks, as per the utility's peak load profile tracks, by aligning them closely with space-cooling equipment use in the residential, small commercial, and large commercial and industrial (C&I) customer segments. A special initiative focused on industrial facilities and others who could make customized curtailment commitments, which sometimes included the shutdown of a facility or a portion thereof. Initial planning for the program began in 2012-2013; customer recruiting began in early 2016.

Residential direct-load control was achieved using two-way Wi-Fi thermostats and one-way load-control switches. A customer engagement portal was provided to customers who chose the Wi-Fi thermostat option. Central Hudson provides an enrollment reward of up to $85 for customers with central air conditioning and a recurring annual reward between $50 and $100 per year, depending on the level of cycling the customer selects. Additional rewards are available for curtailment of pool pumps.

The program also includes a Bring Your Own Device (BYOD) incentive for residential customers with a standby electric generator fueled by propane or natural gas. Itron sought out Generac as the leading provider of standby generators in the region to identify whether there was an opportunity. Study revealed that a surprising number of home generators potentially could be included as program assets. The utility concurred and included generators as part of the BYOD program. Customers are paid $250 per year in return for automatically switching their entire homes to generator power during peak-load reduction events.

Itron's IntelliSOURCE cloud-based software provides the foundation for the program. The utility also uses Itron's services for participant recruitment, program administration, and support (e.g., program tracking, customer resource management, reporting, and dispatching events). Itron has served as the aggregator of aggregators--through contracts with other providers, such as CPower, Itron fulfills their MWh requirements, but all direct-load control is performed in-house. CPower was also responsible for recruiting C&I customers within the three zones, working with a team developing curtailment plans that work for each customer site.

RESULTS:

In the first six months of the program, Central Hudson achieved more than 30% participation of eligible customers within the targeted zone (Fishkill) with the most capacity need. To be eligible, the customer was required to be in a targeted demand management (TDM) zone and have central air conditioning, although exceptions were made for customers with a pool pump or whole home generator.

The utility exceeded the total, first-year MW target for all three zones, achieving 5.9 MW of load reduction compared to the target of 5.3 MW. The utility achieved its 50% load reduction milestone of 8.0 MW in October of 2017 with approximately 3,000 active devices deployed, nine large C&I customers enrolled, and a 40% adoption rate within the Fishkill area.

Overall, results across the utility's service territory have been split about evenly between residential and C&I customers across the whole territory. The Northwest area is heavily skewed towards C&I customers currently, but that's changing. The utility first recruited many C&I customers because they provided a small pool of large customers where higher savings could be achieved. Recruiting high numbers of residential customers takes more time, but is ongoing. Residential savings results are also being achieved and are expected to grow as participation rates increase. Direct mailing and door-to-door methods have been the most effective for residential customer recruitment. The program also utilized email marketing.

KEY TAKEAWAYS AND LESSONS LEARNED:

- **Try several options to engage people.** The program staff found it necessary to use various methods and make multiple contacts to recruit residential customers. While a direct marketing approach of in-person and postal outreach was found to be most effective, the impact of secondary electronic contacts through email marketing was noticeable.
- **No preconceived notion about program design.** A key factor in the program's success was adoption of a technology-agnostic approach. The utility used its procurement process to solicit innovative technology, quantified the need, and selected the solution that was the best fit from both an operational and cost standpoint.
- **Know your service territory.** The program staff needed a deep understanding of the diversity found in the service territory and its demographics. For example, within certain geographic areas, less than 10% of homes have air conditioning, significantly less than the average throughout the service territory.
- **Innovative utility compensation approach.** Because the program aims to defer capital projects that would have otherwise resulted in earnings for Central Hudson, the utility collaborated with regulators to create a unique compensation model which ensures the program is financially beneficial for both the utility and its customers. Instead of a traditional return-on-capital approach, an incentive-

based model was implemented that rewards both Central Hudson and its customers for implementing the least-cost, best-fit alternative to traditional infrastructure upgrades. The formula is as follows:

Central Hudson shares program financial benefits with all customers:

- 70% of benefits will go to ratepayers through natural rate moderation.
- 30% of benefits will be provided to the utility as incentive to run the program effectively.

TO LEARN MORE (SUPPORTING DOCUMENTATION/SOURCES):

- Itron case study

CON EDISON—BROOKLYN QUEENS DEMAND MANAGEMENT

OVERVIEW:

- **Size and Location:** ~52 MW in New York City
- **Challenge/Opportunity:** Sub-transmission feeder constraint at a substation
- **Primary Drivers:** Internal management decision with regulatory mandate
- **Technology Focus:** Energy efficiency; demand response; distributed generation; electric storage
- **Sourcing:** Customer program
- **Utility and other key allies:** Consolidated Edison (Con Edison) with New York State Energy Research and Development Authority (NYSERDA) and National Grid (gas provider). Other key allies included implementation contractors from the existing programs, direct customer interaction, demand response, and solution providers for technologies such as fuel cells and CHP.
- **Status:** Active since 2014 and was planned to end in 2018; however, Con Edison has received an extension to procure additional load-reducing NWA resources

SUMMARY:

The Brooklyn Queens Demand Management program (BQDM) is one of the largest NWA projects in the U.S, with close to 52 MW of traditional and non-traditional resources. This project was designed to help delay the construction of a new substation beyond initial load-relief projections. This project demonstrates the ability to implement a diverse portfolio of distributed energy resources (DER) technology to drive demand reduction and defer traditional infrastructure upgrades that would require a large investment.

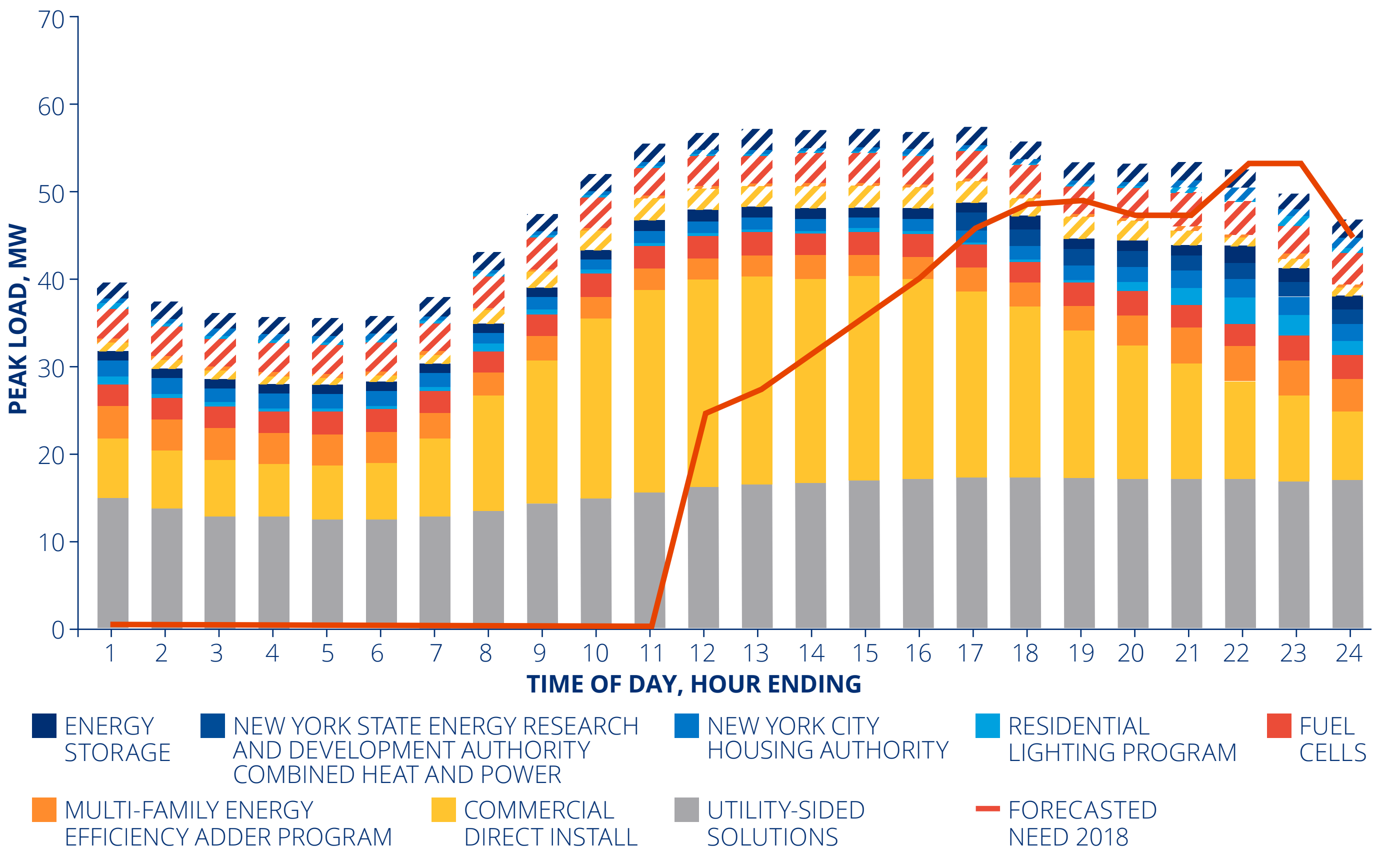
CHALLENGE AND OPPORTUNITY:

Con Edison's traditional approach to address the potential overload of the sub-transmission feeders Brownsville No. 1 and No. 2 substations would have been to construct a new area substation, establish a new switching station on the existing property of the Gowanus station, and construct sub-transmission feeders between the new Gowanus switching station and the new area substation by 2017. Instead, the utility decided to defer that investment by implementing a combination of traditional and non-traditional customer-side and utility-side solutions. The targeted areas in the BQDM program include north-central and eastern Brooklyn neighborhoods, more specifically parts of Greenpoint, East Williamsburg, Bushwick, Bedford-Stuyvesant, Crown Heights, East Flatbush, Brownsville, and East New York. Targeted areas also include southwestern Queens neighborhoods, more specifically parts of Richmond Hill, Howard Beach, Broad Channel, Ozone Park, South Ozone Park, Woodhaven and Kew Gardens. The peak load-relief need occurred at night (9-10 PM). The overload period was 12 hours, from noon to midnight, however.

SOLUTION:

The utility filed a petition with the NY Public Service Commission on July 15, 2014 proposing to implement BQDM to consist of a total of approximately 52 MW of non-traditional, utility-side (11 MW) and traditional, customer-side solutions (41 MW). The program was approved to be implemented with a $200 million budget. After the request was approved, Con Edison issued a request for project proposals, evaluated responses from vendors, and negotiated contracts. Simultaneously, the utility proceeded with the 11 MW of non-traditional, grid-based NWA projects. The current portfolio includes a variety of solutions: fuel cells; combined heat and power (CHP); energy efficiency (EE) projects with the city

EXAMPLE OF HOURLY LOAD REDUCTION PROVIDED BY THE DIFFERENT NWA RESOURCES



Source: Con Edison, 2018.

and state; battery storage; solar photovoltaic (PV) systems; and conservation voltage optimization (CVO).

To begin identifying potential solutions able to achieve load relief immediately, the company developed a market solicitation, while at the same time determining program incentives to increase adoption of energy efficiency measures in the targeted areas. An initial Request for Information (RFI) was launched by Con Edison seeking load-reducing projects in the targeted areas. Some proposed solutions would provide a portion of the load savings, while others would provide total, customer-side load reduction solutions.

Implementation first started with EE initiatives that leveraged existing programs alongside the utility building out contracting relationships with third parties for more innovative technologies. This approach created diversity while simultaneously engaging customers and vendors. Marketing efforts included providing additional incentives beyond established amounts to target small businesses, multifamily, and commercial and industrial (C&I) customers to make the installations, such as efficient lighting systems, essentially free to the customer.

The utility created a program specifically targeting multifamily (1-4 unit) residential homes with an EE campaign. The utility's marketing strategy began with neighborhood canvassing in an unmarked van and eventually evolved to neighborhood canvassing with EE measures giveaways. The utility later switched to evaluations scheduled by call center and conducted by the implementation contractor in a utility-branded vehicle. The BQDM program also provides incentives to government agencies to identify and implement demand-reducing solutions, such as EE.

The utility has worked closely with CHP program administrators, as well as National Grid, the natural gas provider in the area, and its CHP team. The BQDM Project provided additional funds up to the base incentive level that NYSERDA offers under its CHP Acceleration Program for eligible installations in the BQDM area. The incentive was feasible and did not pay for or exceed 100% of the total cost of the projects. Solution providers were incentivized to target their efforts in the BQDM areas with heightened requirements to help ensure load reduction.

Fuel cells were also implemented within the BQDM area to provide benefits to Con Edison and its customers. The utility engaged customers and a fuel-cell vendor to allow and incentivize the adoption of fuel cells at eligible customer locations. Customers in the BQDM area with verified electric service account numbers were eligible to participate. BQDM allows for a multi-technology installation of energy storage and fuel cells at one affordable housing customer location. Other solutions implemented through vendor and customer engagement include a demand response (DR) auction hosted to procure load reductions for 2017 and 2018, as well as a solar PV program that provides load reduction during earlier times of the day.

On the non-traditional utility-side, Con Edison implemented enhanced, efficient voltage control via CVO to reduce peak loads in the BQDM area. Con Edison will also be installing a 12 MWh battery energy storage system (BESS) configured to provide power for six or 12 hours. The configuration allows a choice of discharge: either 1 MW for 12 hours, or 2 MWs for 6 hours. The project is planned for completion during the fourth quarter of 2018.

RESULTS:

The BDQM program met objectives by implementing both traditional and non-traditional customer side and utility-side solutions. An extension to this program has been granted to help meet additional load reduction needs. Savings achieved through the portfolio of measures successfully delayed the buildout of a new substation beyond the initial load relief projections. With the announced program extension, Con Edison is looking for additional load reductions to delay the build out further and perhaps permanently defer the new substation. Con Edison released requirements for a closed bid auction, seeking additional load reduction solutions at customer locations. In addition to the auction, the utility is evaluating additional load reduction opportunities for 2019 and 2020 through continued collaboration with partners and customers.

Through the initial RFI process, Con Edison determined the portfolio approach could attract enough resources that could manage not just the peak load but the overall substation load profile. Energy efficiency initiatives across different programs (e.g., small- to medium-business [SMB], multifamily [more than four units]), started out as the lead contributor, delivering about 15 MW in savings during peak hours, as well as during non-peak times. Today, baseload technologies such as fuel cells and CHP will provide a total of approximately 8 MWs of peak-load reduction. Other load relief is coming from energy storage, 1-4 unit residential energy efficiency, governmental agencies, and demand response. Solar, storage, and other technologies also provide load relief at non-peak times, such as earlier in the day.

The figure on pg 53 shows the hourly load reduction provided by the different NWA resources.

Another measure of program success is the increased levels of engagement with customers and vendors. The BQDM Project is often referenced in community group interactions for its positive public response. Some local employers have referenced the program as a driver for new hires in the area specifically targeted for the project. Vendor engagement has helped to diversify the utility's resource portfolio to include new market partners capable of deploying these load reducing solutions.

KEY TAKEAWAYS AND LESSONS LEARNED:

- **Some technologies take longer.** A primary lesson learned from the field is that launching first with aggressively targeted marketing on existing EE program offerings bought time to allow for the longer lead times needed to introduce more complex technologies, such as distributed generation.
- **A general RFI in the beginning may help to focus follow-on solicitations.** An initial RFI helped shape subsequent solicitations by providing a better understanding of how different technologies fit in. For example, one solution provider who responded to the RFI worked with the utility to adopt the installation of fuel cells at customers' locations. For future solicitations, the utility developed a standard proposal template that allows for a consistent evaluation of resource solutions on a line-by-line basis to see how it fits in the portfolio. Con Edison continues to gain lessons that can be applied to future market solicitations for new projects.
- **Project learnings can be scaled downward.** Key lessons learned about market engagement and the type of need addressed are being incorporated into planning for future, smaller-scale utility projects, such as targeted primary feeder projects with limited numbers of or hard-to-reach customers as compared to larger-area substation projects that provide load reduction within a whole network.
- **Financial and non-financial risks persist.** Challenges that the utility faced and is working on incorporating into planning include: customer acquisition, vendor contracting, permitting, and municipal planning and coordination. The utility intends to maintain communications with all stakeholders to identify barriers, ensure understanding of the program, and communicate available opportunities.

TO LEARN MORE (SUPPORTING DOCUMENTATION/SOURCES):

- BQDM Docket for updates on the program
- Non-Wire Solution Opportunities

CONSUMERS ENERGY—SWARTZ CREEK ENERGY SAVERS CLUB

OVERVIEW:

- **Size and Location:** Up to 1.6 MW in Swartz Creek, Michigan, a small rural, suburban town southwest of Flint
- **Challenge/Opportunity:** Distribution grid constraint
- **Primary Drivers:** Internal management decision relative to regulatory mandate
- **Technology Focus:** Energy efficiency; demand response
- **Sourcing:** Customer program
- **Utility and other key allies:** Consumers Energy with ICF and Natural Resources Defense Council
- **Status:** Active since October 2017

SUMMARY:

The Swartz Creek Energy Savers Club is a pilot project to investigate EE and DR opportunities to avoid or defer distribution system investments and provide cost savings for customers. Consumers Energy recruited residential customers to cycle their air conditioners and adopt EE measures. This project's goal was to reduce load requirements below the 80% maximum summer capacity and defer a $1.1 million infrastructure investment.

CHALLENGE AND OPPORTUNITY:

At the request of the Natural Resources Defense Council (NRDC) as part of a 2014 rate settlement, Consumers Energy developed a pilot project to investigate opportunities to use energy efficiency (EE) and demand response measures to avoid or defer distribution system investment with the potential to yield cost savings for customers. A substation in Swartz Creek was selected based on the following criteria established in 2015 by Consumers Energy with input from NRDC:

- Distribution system upgrades were being driven by load growth;
- Deferred cost of at least $1 million if project was successful;
- Infrastructure upgrade requirement was at least two to three years out.

The goal was to reduce load requirements below the 80% maximum summer capacity level to defer planned construction of $1.1 million of infrastructure. The project aimed to reduce peak load by 1.4 MW by the end of 2018, or 1.6 MW by the end of 2019.

The utility evaluated multiple measures and selected 16 on which to focus (five residential and 11 commercial) using the following adoption assumptions:

- Past program participation;
- Uplift in participation based on community-based model;
- On-the-ground observations.

SOLUTION:

The program kicked off in October 2017 and was initially slated to end in 2018. Based on results as of August 2018, it may be extended to run through 2019, or a second location may be identified.

The core program implementation components are:

- **An Energy Ambassador** responsible for integrating into Swartz Creek, gathering intelligence, garnering participation via outreach, and providing a line-of-sight for customers to Consumers Energy programs and rebates.
- **An Energy Task Force** that includes several local stakeholders, including Consumers Energy Community Affairs.
- **A Community Project**, which serves to motivate Swartz Creek residents and businesses to participate in the program.

- **A Multi-channel Marketing Campaign** that includes heavy, "boots on-the-ground" project team participants and leverages lessons learned from a previous pilot structure that focused on local groups competing to see who could sign the most people up for program participation.
- **A Unique Brand and Website** that enables customers to learn about Consumers Energy programs that help reduce demand, to join Energy Savers Club, win prizes, and vote for their favorite community project. Customers visit the website to register, vote on their favorite project, and learn about the programs to help reduce demand.

There are currently two grassroots community projects that generate awareness for the program by equipping local champions to campaign for their project. Traditional media campaigns have been shown to raise awareness without action necessarily following. In contrast, learning about programs through family and friends not only raises awareness but is more likely to cause people to take action. The two community projects being considered entail:

1. Converting an empty lot into a plaza in downtown Swartz Creek that would be used for civic events, such as a farmer's market and craft shows;
2. Carrying out a project to connect downtown Swartz Creek to an existing walking-biking trail to provide safe recreational opportunities.

The utility recently engaged the school district's STEM coordinator, a newly created position, to develop a third option related to a renewable energy project (details to be determined). The utility is hoping that this third option will generate interest and drive participation of customers with school-aged children.

ICF is providing staff to serve as an Energy Ambassador, reaching out to community leaders such as city managers and school administrators to encourage them to embrace EE program initiatives, such as lighting projects. Schools were encouraged to take advantage of an existing green revolving fund as a means of funding efficiency projects. However, while the schools have completed several lighting projects and have more in the pipeline, they were reluctant to participate in the green revolving fund and the opportunity was lost for 2018.

RESULTS:

Early results indicate that the program is having a positive impact on reducing demand through increased program participation. The majority of the savings came from commercial lighting programs and residential DR programs. Based on initial analysis, residential DR programs are estimated to meet almost the entire 2018 savings target of 1.4 MW. However, the projected participation rate required to achieve those savings was high and likely unattainable, and the air conditioner cycling program kW contribution was cut from 1.12 kW to 0.58 kW based on averages noted during the 2017 event season. Marketing for the program is adapting by adding a door-to-door component targeting residents on the substations' specific circuits in July and August 2018.

Recruitment of commercial and industrial customers has been challenging because there are only 300 mostly small businesses in the area with economic limitations and some inflexible load profiles. The most significant commercial customer on the targeted circuits opted out of EE program participation, which limits opportunities.

Working in collaboration with NRDC, Consumers Energy is looking for opportunities to increase EE program savings from both residential and commercial perspectives. Initially, the utility wanted to achieve the savings without making use of additional incentives. However, the utility is adding targeted bonus incentives to existing programs. Those programs include residential appliance recycling, insulation and windows upgrades, air conditioner (AC) tune-ups, and AC replacement, as well as commercial lighting and refrigeration upgrades.

KEY TAKEAWAYS AND LESSONS LEARNED:

- **Load Forecasts are Dynamic.** Anticipated load growth at the substation did not materialize. Forecasts need to incorporate the potential for load shift from another substation.

- **Leverage Partner Outreach.** A city manager's social media posts always show a blip of requests for free EE kits or voting for a community project option. Program staff are exploring why some do not vote for a community project when they register to get the free kit.
- **Program Start-up Components are Replicable.** Design projects so that the expense and effort that goes into structuring new programs can be replicated when launching in other locations.
- **Community Size and Economy are Limiting Factors.** The community-based approach seems to work for the location, but challenges with generating commercial and industrial investments in programs have been observed. Potential to create a diverse set of DER's should be a key consideration in site selection.

TO LEARN MORE (SUPPORTING DOCUMENTATION/SOURCES):

- Non-Wires Alternatives Lessons and Insights from the Front Lines, presented at the 36th PLMA Conference, Cambridge, Mass., Nov. 2018. Michael DeAngelo, Avangrid; Mark Luoma, Consumers Energy; Steve Fine, ICF; Richard Barone, Hawaiian Electric Company; Erik Gilbert, Navigant, Moderator.

GRIDSOLAR, LLC—BOOTHBAY

OVERVIEW:

- **Size and Location:** 1.85 MW in Maine
- **Challenge/Opportunity:** Sub-transmission constraint/reliability
- **Primary Drivers:** Regulatory mandate
- **Technology Focus:** Energy efficiency; energy storage (battery and thermal); demand response; renewables; back-up generators
- **Sourcing:** Direct procurement (competitive-bidding process and sole-sourced)
- **Utility and other key allies:** GridSolar, LLC with Central Maine Power Company, Ice Energy, Convergent, and Efficiency Maine Trust
- **Status:** Limited-duration project from 2013-2017

SUMMARY:

The Boothbay Pilot Project, by GridSolar, applied a mix of NWA solutions to address forecasted load concerns. GridSolar implemented a pilot project that incorporates a 500 kW, 3 MWh Convergent supplied battery energy storage system (BESS), 250 kW of Ice Energy's thermal storage units, a 500 kW, diesel-fueled back-up generator, EE commercial lighting, and rooftop solar PV systems. The load in the Boothbay region never reached forecasted levels, so full NWA deployment was not required.

CHALLENGE AND OPPORTUNITY:

In its 2008 rate case filing with the Maine Public Utilities Commission (MPUC), Central Maine Power Company (CMP) proposed a 300-mile, $1.5 billion transmission upgrade involving construction of multiple transmission lines and high voltage substations to address reliability concerns resulting from forecasted increases in peak-load conditions on the grid. GridSolar intervened in the case, arguing that: 1) CMP's load forecasts were way too high and that the more likely lower load forecasts did not justify the investment, and 2) the number of hours for which the $1.5 billion upgrade would be needed were very limited even under CMP's high load forecast (less than 100 hours immediately, and less than 500 hours a year in the long-term). In effect, CMP was proposing a very expensive baseload solution to a peak load problem that GridSolar believed could be addressed more efficiently by focusing on tailored alternatives.

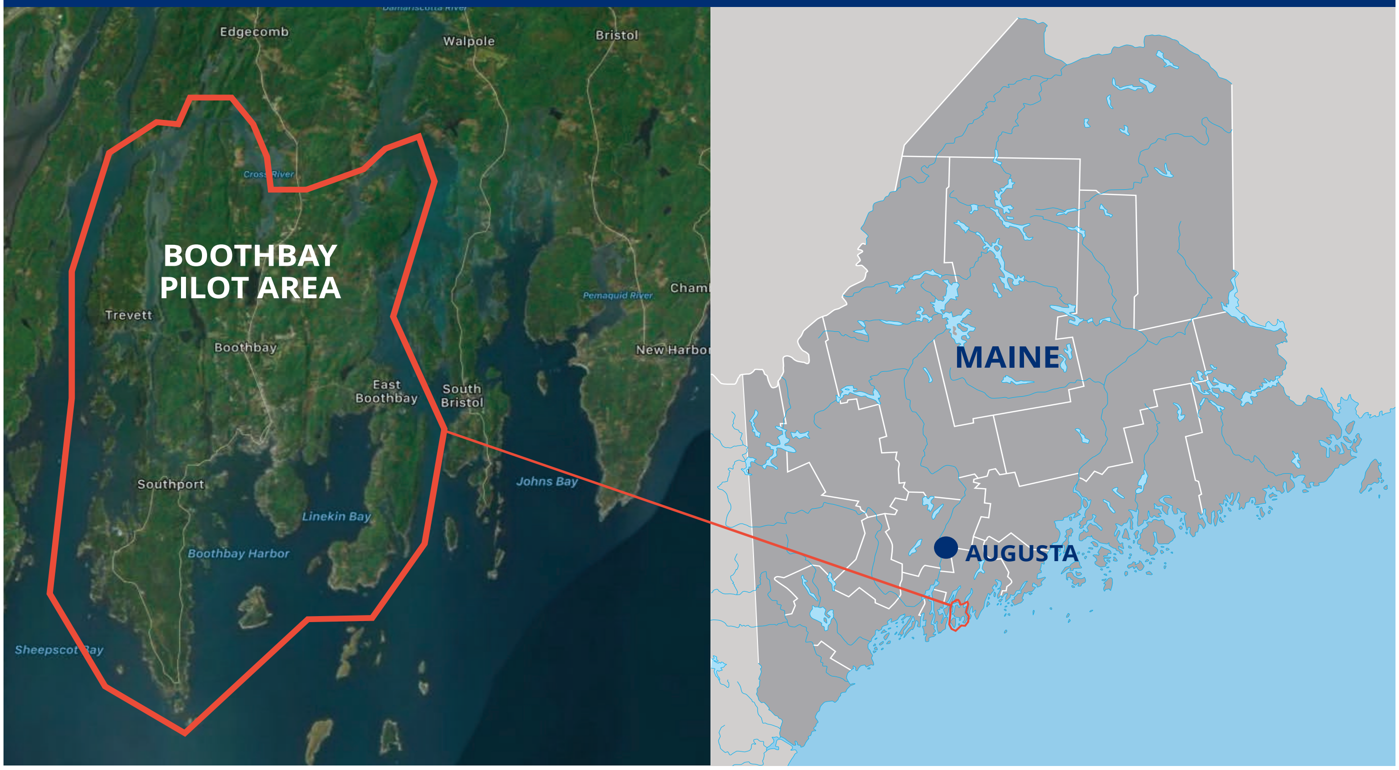
GridSolar originally proposed a solution consisting of a major buildout of solar photovoltaic (PV) generation in combination with back-up diesel and natural gas-fired generators. MPUC accepted a comprehensive settlement in which the large majority of the CMP transmission solution would be built, but two areas of the state, the mid-coast and the Portland regions, would be carved out for the purpose of allowing GridSolar to develop NWAs to address the localized grid reliability issues in these two regions.

SOLUTION:

CMP identified a smaller, localized transmission need in the Boothbay peninsula with forecasted peak loads expected to exceed the carrying capacity of key circuits by about 2 MWs. GridSolar proposed to develop 2 MW of DER in the Boothbay region so as to eliminate the need for the new transmission line. The total cost was estimated to be about $6 million, less than a third of the cost of the CMP proposal. MPUC accepted GridSolar's proposal and ordered CMP and GridSolar to implement it as a pilot project to test the viability and effectiveness of NWAs.

Project management was under the direction of GridSolar, which operated the project pursuant to a contract with CMP. All NWA resources, except energy efficiency (EE), were procured by GridSolar

PROJECT AREA, BOOTHBAY PENINSULA



Radial nature of electric service and local distribution circuits on the Boothbay peninsula defines the electric region for the Pilot Project—Total Peak Load—approx. 30 MW.

Source: GridSolar, 2018.

through competitive-bidding processes in 2013. GridSolar did not own any of the NWA assets to ensure that there were no conflicts of interests that would discourage other parties from offering bids to provide NWAs. EE was procured through a sole-source agreement with the Efficiency Maine Trust.

Between 2013 and 2015, approximately 1.8 MW of NWAs were deployed:

- **Storage:** This project included the first 500 kW, 3 MWh BESS installed in Maine, and GridSolar managed it as needed to meet load conditions on the grid.
- **Back-up Generation:** The 500 kW diesel generator provided flexibility to meet grid conditions when they would have unduly burdened some of the other resources.
- **Demand Response:** Ice Bear systems replaced aging air conditioning systems on commercial buildings with a contractually guaranteed six hours of capacity when called. GridSolar directly controlled dispatch of the Ice Bear units. Ice Bears provided as much as 12 hours of air conditioner run-time under normal use (e.g., no call days). On call days, GridSolar could delay their start, and let them run later in the evening; calls took precedence over normal use.
- **Solar PV:** The solar PV systems operated passively.[42] Since they were located downstream of the key constraint on the grid, they had the effect of lowering the amount of energy required to be imported into the region by

42 i.e., they delivered energy and capacity based on weather conditions.

providing additional capacity on the constrained transmission line.

- **Energy Efficiency:** In order to achieve reliable EE delivery (i.e., installation of the EE measures), GridSolar relied on Efficiency Maine Trust as the sole source to deliver the EE component.

To complete the project, it was necessary to secure interconnection agreements for all NWA resources that either generated electricity or that had the ability to deliver electricity to the electric grid. This created a problem on one circuit that served the small industrial park in Boothbay, where both the battery storage and back-up generator were proposed to be located. CMP determined that the combined capacities of the two NWA resources exceeded minimum electric loads on the circuit, which could potentially result in reverse power flows to the upstream substation that would cause the circuit to trip. CMP agreed to provide interconnection agreements since these two NWA resources would only be dispatched during periods of peak loads, when circuit loadings were at their highest levels. These levels were well above the capacities of the NWA resources so that no reverse power flows would ever occur.

CMP initiated dispatch instructions and GridSolar controlled and dispatched the active NWA resources. These dispatch instructions were enabled through the creation of a Network Operation Center developed and operated by GridSolar. CMP provided real-time load data on each distribution circuit in the Boothbay region so that GridSolar could manage the resources effectively (e.g., testing diesel generators prior to calls; ensuring batteries were fully charged; planning ahead to make ice for thermal storage).

RESULTS:

The project ran from Q4 2013 through Q2 2018 and was terminated because electric load growth did not materialize as the utility originally forecasted. As a result, the NWA resources were no longer necessary to ensure grid stability under N-1 conditions in this load pocket. The Boothbay Pilot was successful in providing an NWA solution to a potential grid reliability problem from peak load conditions in a specific load pocket on a sub-transmission grid of CMP. GridSolar prepared two reports for general release. An interim report on the project was released in January 2016; a final report was issued in Q2 of 2017.

One critical measure of success was that Maine ratepayers saved more than $12 million in present value terms compared to the transmission alternative. When projects include EE and solar PV, the community gets involved, learns to better understand the grid, and sees the benefits once they are implemented.

KEY TAKEAWAYS AND LESSONS LEARNED:

NWA solutions can be highly cost effective under certain circumstances, particularly in areas where load growth is relatively slow. However, reliability requirements are being driven by peak-load conditions. NWAs emphasize the need to accommodate DERs through the development of a smarter electric grid. This is essential to meet the 2050 carbon neutral goals set by many cities across the country. GridSolar offers the following takeaways:.

- **Reliability:** NTA or NWA resources are able to provide grid reliability benefits that are comparable to those provided by transmission lines and related equipment at a lower cost and with significantly more flexibility.
- **Control vs. Ownership:** Key points of contention include determining who controls, develops, and operates solutions. The utility can procure the resources or enter into contracts for delivery of the services (GridSolar advocates for the latter), which separates ownership from control.
- **Grid Smart Coordinators should be considered:** There may be a need for a distribution system ISO that has responsibility for these NWA alternatives (i.e. a Smart Grid Coordinator). Like Regional Transmission Operators (RTOs) and ISOs across the country, a Smart Grid Coordinator should not be

permitted to own or have any financial interest in NWA resources to avoid conflicts of interest.

- **Multiple value streams:** It is hard to have the same NWA resource serve two purposes (PJM, ISO-NE, NYISO for DR versus the utility for transmission replacement). For example, one resource cannot be called to both reduce load and provide transmission at the same time.
- **In cases requiring EE**, parties should consider using third parties on a sole-source basis to provide the EE resources as an NWA.

TO LEARN MORE (SUPPORTING DOCUMENTATION/SOURCES):

- Interim Report Boothbay Sub-region Smart Grid Reliability Pilot Project, March 2014
- Final Report Boothbay Sub-Region Smart Grid Reliability Pilot Project, January 2016
- Northeast Energy Efficiency Partnership, A Look Inside the Region's Latest Non-Wires Alternative Projects and Policies, December 2016

NATIONAL GRID—OLD FORGE

OVERVIEW:

- **Size and Location:** 19.8 MW, 63.1 MWh in upstate New York
- **Challenge/Opportunity:** Distribution grid constraint and grid resiliency
- **Primary Drivers:** Internal management decision
- **Technology Focus:** Electric storage
- **Sourcing:** Direct procurement
- **Utility and other key allies:** National Grid
- **Status:** In development

SUMMARY:

National Grid's Old Forge project is still in development. The NWA project seeks to improve reliability on a radial, 46 kV sub-transmission line that feeds five substations in three New York counties. This project highlights the challenges of incorporating a battery energy storage system (BESS) into the transmission and distribution system for reliability proposes where the resource has to be available and respond to unpredictable outages

CHALLENGE AND OPPORTUNITY:

The project goal is to improve the reliability on a radial, 46 kV sub-transmission line that feeds five substations in three New York State counties. The towns and counties impacted by this project include: Alder Creek, Oneida County; White Lake, Oneida County; Old Forge, Herkimer County; Eagle Bay, Herkimer County; and Raquette Lake, Hamilton County.

This area of New York State is in the Adirondack region, which does not have an installed natural gas system. Natural gas-fired electricity generation has been proposed for some of National Grid's other non-wires alternative (NWA) requests for proposal (RFPs), but a natural gas-fueled solution is not an option for Old Forge.

Four of the five sub-stations fed by this 60-mile-long sub-transmission line are located inside Adirondack Park. The park has strict guidelines for development and tree trimming. Constructing a loop feed to the northern end of the sub-transmission line is not viable due to permitting and limited development allowed in the Adirondack Park. Portions of the 46 kV line are routed in forested areas away from the main roads. Some of the insulator failures on the sub-transmission line are related to gun fire as this is a popular area for seasonal hunting.

An engine generation technology would be able to participate in various energy markets and still be available in real time when called upon to respond to outages created by tree damage, motor vehicle accidents, or other causes. The downside of the BESS, if selected, is the limited run time of the battery: utility crews would be challenged to restore power within the discharge time of the battery system.

This project is also challenged to meet BCA testing requirements. The project is outside the term of the utility's five-year Capital Investment Plan. However, National Grid will move forward if a plan develops to create a project with a benefit-cost ratio (BCR) greater than 1.0.

SOLUTION:

The Old Forge Project presents an opportunity to significantly improve the CAIDI and SAIFI reliability scores for the 7,700 residents and commercial businesses served in the area. This project will essentially create a microgrid which will be supplied by the main utility grid for a large majority of annual-hours. When an outage occurs, the microgrid will sectionalize the fault and pick up many of the impacted customers north of the fault by operating in island mode, which would involve various controls and switching schemes.

National Grid has issued an NWA RFP and is working through various options with the primary short-listed bidder to determine if the utility can achieve a project with a BCA score of 1.0 or greater. National Grid is also keeping the staff of the State of New York Department of Public Service informed of the obstacles related to developing this project. The primary technology is a BESS that would contribute to the recently announced New York State goal of installing 1,500 MW of energy storage by 2025. The challenges of this project include siting equipment and land cost, complying with regulations of the Adirondack Park Agency and local towns, interconnection costs at the point of common coupling (PCC), and overall project cost and financing.

An RFP was published in early 2017 and distributed to all vendors participating in the NWA RFP process. The RFP is open to all DER technologies. Eight out of the nine proposals received involved BESS technology. The other offered a monitoring platform. The BCA tool is being applied to each proposal and final decisions are expected in Q4 2018.

RESULTS:

The NWA team at National Grid is evaluating all options to develop a project that meets the NWA BCA test that has been filed with the State of New York Department of Public Service. National Grid is exploring new technologies to reduce the interconnection cost at the PCC. The utility continues to evaluate the feasibility of providing land assets for the location of DER technologies. The utility is working with the short-listed, primary bidder so both parties fully understand each others' systems and opportunities to reduce cost and get to a BCA score of 1.0 or greater.

KEY TAKEAWAYS AND LESSONS LEARNED:

- **Interconnection costs become a significant cost barrier** for projects which require multiple points of common coupling. Also, interconnection costs in general can become a significant part of the solution cost for small projects.
- **The utility is constantly learning from each NWA RFP** and has tweaked its RFP format to allow market participants to streamline their offering in terms of pricing and technology. This is to eliminate confusion in evaluating bids.
- **The market for services** that DER technologies can participate in at the distribution level is still developing.
- **Natural gas availability** increases the potential types of DERs that may solve critical problems.
- **National Grid's System Data Portal is a vital resource** for potential NWA bidders to better understand the National Grid system. National Grid is expanding the capabilities of the System Data Portal on an ongoing basis.

TO LEARN MORE (SUPPORTING DOCUMENTATION/SOURCES):

- National Grid System Data Portal
- New York State Department of Public Service filings for National Grid Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Case 14-m-101:
- National Grid NWA Opportunities

NATIONAL GRID—TIVERTON NWA PILOT

nationalgrid

OVERVIEW:

- **Size and Location:** 1 MW in Tiverton and Little Compton, Rhode Island
- **Challenge/Opportunity:** Distribution grid constraint
- **Primary Drivers:** Substation and feeder upgrade deferral; Internal management decision
- **Technology focus:** Energy efficiency and demand response
- **Sourcing:** Customer program
- **Utility and other key allies:** National Grid, Whisker Labs, Opinion Dynamics Corporation
- **Status:** Began in 2012 and completed in 2017

SUMMARY:

The Tiverton Non-Wires Alternative (NWA) Pilot utilized a customer-driven load curtailment program called DemandLink that focused on automated demand response (DR). The NWA pilot program included a wide variety of DR and energy efficiency (EE) resources, such as Wi-Fi thermostats, heat pump water heater rebates and installation, and window air conditioner (AC) replacement and recycling. Although the project never fully realized the goal of 1 MW of load reduction after five years, the Tiverton NWA Pilot did defer the Tiverton Substation and feeder upgrades.

CHALLENGE AND OPPORTUNITY:

The Tiverton NWA Pilot was an NWA project utilizing demand response and energy efficiency programs in the communities of Tiverton and Little Compton, Rhode Island. The project was initiated with the Rhode Island System Reliability Procurement (SRP) 2012 Plan filing. National Grid designed this program to test whether geographically-targeted EE and DR could defer the need for a new 1 MW substation feeder upgrade to serve 5,200 customers (80 percent residential with the remainder being small businesses). This upgrade was needed to alleviate distribution grid constraints arising from hot weather summer peaking in the two municipalities. Although the Tiverton NWA Pilot as a program was holistic and contained a broad range of EE and DR solutions, implementation of the different incentives and rebates required separate processes in order to properly credit customers, while regulatory restrictions prevented value stacking. However, the holistic approach improved the communications between all the different parties and improved management across programs.

SOLUTION:

The 6-year pilot began in 2012 and ended in December 2017, with the objective of deferring a $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 project employed a variety of marketing tactics to refresh the message and engage new participants in all utility-driven EE and DR programs. AMR was not available for the project, so it required some new monitoring techniques.

The DemandLink DR program component was the predecessor to ConnectedSolutions and was one of the first steps for National Grid into DR. ConnectedSolutions plans to incorporate innovative programs like Bring Your Own Battery, among other enhancements, as implementation of demand response progresses.

The city managers in Tiverton and Little Compton were instrumental in assisting with community outreach by engaging local citizens through social media and organizing community meetings to discuss the necessity and benefits of the project. The auditors on site, RISE Engineering, were essential in helping with door-to-door implementation and EE installations.

RESULTS:

Total deferment of the substation upgrade with a 1 MW load-offset goal was not fully achieved. However, the Tiverton NWA Pilot, in conjunction with other projects, was successful in achieving a qualitative goal of deferring the $2.9 million feeder project. The holistic portfolio approach satisfied the need: the substation upgrade continues to be deferred. Forecast changes and weather pattern changes are being considered, while National Grid acknowledges there may still be need for an upgrade in the future.

In 2017, National Grid implemented automatic meter reading (AMR) as well as time-of-use rates. This major change is helping customers see the cost of energy at varying times and prompting them to shift their usage to off-peak times.

Another RFP was released in 2017 to identify potentially cost-effective, market-based solutions to reach the original 330 kW target. National Grid is taking a RFP-based approach similar to others in the region. National Grid, in its 2019 System Reliability Procurement Report, discussed the project to date and future expectations in detail.

In response to the Tiverton NWA Pilot, National Grid proposed another NWA project called the Tiverton-Little Compton NWA Project (TLC NWA Project) in their 2019 SRP Report. As explained therein, the NWA project would operate through the summer of 2022. This will kick off with an RFP to be released in 2019 to identify cost-effective market-based solutions to further defer the Tiverton Substation upgrade. The TLC NWA Project is intended to defer the $2.9 million substation upgrade detailed in the Tiverton NWA Pilot proposal further.

KEY TAKEAWAYS AND LESSONS LEARNED:

National Grid modeled the DemandLink pilot using the standard total-resource-cost test, except for the distribution benefit. With those benefits, they excluded the value from the regional avoided cost study and replaced that with the annualized benefit of deferring the feeder investment for each of the four years.

- **It's difficult to cost-out a seasonal need** if the assets can't be evaluated for year-round use.
- **Thermostats for central AC and heat pump water heaters were effective** across both residential and small businesses.
- **Smart plugs operating window AC units were not effective.** People would either not use the smart plug or bypass at the AC unit whether a residence or a small business.

TO LEARN MORE (SUPPORTING DOCUMENTATION/SOURCES):

- 2017, 2018, and 2019 Rhode Island System Reliability Procurement Report SRP Reports
- NEEP, EM&V Forum and Policy Brief: State Leadership Driving Non-Wires Alternative Projects and Policies, 2017.

SOUTHERN CALIFORNIA EDISON (SCE)—DISTRIBUTION ENERGY STORAGE INTEGRATION (DESI) 1

OVERVIEW:

- **Size and Location:** 2.4 MW, 3.9 MWh in Orange, California, 35 miles from Los Angeles
- **Challenge/Opportunity:** Distribution grid constraint
- **Primary Drivers:** Internal management decision
- **Technology Focus:** Electric storage
- **Sourcing:** Direct procurement through competitive-bidding process to identify sole source
- **Utility and other key allies:** Southern California Edison with NEC Energy Solutions
- **Status:** Active since May 2015

SUMMARY:

SCE's DESI 1 sought to defer a distribution upgrade through circuit load management with the deployment of a front-of-the-meter, grid-interactive battery storage application. This BESS was maintained by a third party, located in an extremely compact customer location, and owned and operated by the utility as a grid asset. This project has been in operation for three years to date.

CHALLENGE AND OPPORTUNITY:

Distribution Energy Storage Integration (DESI) 1 is Southern California Edison's (SCE's) first pilot-production, distribution-connected BESS. It is designed for distribution-upgrade deferral through circuit load management.

The BESS is connected to the 12 kV Scarlet distribution circuit, which serves various commercial and industrial customers in the City of Orange. One of these customers manufactures large drill bits for offshore oil platforms. Part of the manufacturing and delivery process includes time-critical testing of the drill bits in one of several on-site test bays. Each drill bit test can add several megawatts of load to the customer's service, typically during on-peak periods. These large increases in demand can potentially cause the Scarlet distribution circuit to reach or exceed its planned loading limit (PLL) during peak-load conditions.

SOLUTION:

DESI 1 was procured through a competitive bidding process as a turn-key system. The manufacturer was responsible for providing a complete, integrated, operational BESS, as well as providing maintenance and warranty services per utility specifications. SCE was responsible for providing the interconnection facilities, location, and site preparations necessary to receive the BESS. SCE released a request for proposals (RFP) in early 2014 and awarded a contract to NEC Energy Solutions in July 2014. Construction of interconnection facilities and site preparations started in early 2015. The manufacturer completed system commissioning and associated tests in May 2015. NEC Energy Solutions completed acceptance testing on May 22, 2015. SCE then took operational control of the system.

DESI 1 is a 2,500 kilovolt-ampere (kVA), 3,900 kilowatt-hour (kWh), lithium-ion BESS designed to be extremely compact to allow installation on a 1,600 square-foot easement within the customer's industrial facility. The physical footprint also includes 12 kV switchgear, a transformer, a power conversion system (PCS), an energy storage enclosure, and a communication cabinet.

The BESS has several active and reactive power operating modes, but it is primarily designed to monitor the Scarlet distribution circuit phase-current and discharge as needed to prevent the current from exceeding the PLL. Unlike some other SCE battery systems, this project is a dedicated, single-point grid reliability device rather than a dual-use system (one that can also participate in the CAISO market when not being used for reliability).

The customer provided an easement for the BESS inside their existing fence line, as well as for interconnection facilities on the adjacent parkway. This arrangement was advantageous to SCE because a typical, one-year turnaround from conception to implementation can become two or three years if land acquisition is required.

As with many BESS deployments in an urban environment, the location selection process proved challenging. DESI 1 was a very compact site. To fit all equipment on the site while still meeting power and energy requirements, SCE and NEC had to use a custom PCS enclosure, a liquid-cooled PCS, and a custom, prefabricated battery building (as opposed to the vendor's normal containerized offering). The project site also had many existing underground structures, including utility electric ducts, a 6 cubic-foot vault with manhole, a sump, an 8-inch fire water pipe, and an 8-inch gas line. All project underground conduit runs had to accommodate these structures, and all above-ground equipment had to be located so the sump, manhole, and gas pipe right-of-way remained fully accessible.

SCE prepared the site, including seeing to all civil contracting work. NEC installed and commissioned the BESS. This required extensive coordination between the civil contractor and BESS vendor. As of 2018, all future SCE BESS procurements will use a full engineering-procurement-construction (EPC) approach whereby SCE provides the site and the vendor prepares the site and installs the BESS using its own contractor.

RESULTS:

DESI 1 has successfully dispatched multiple times to keep the circuit load from exceeding PLLs, and it has met its original objective. Most recently, DESI 1 was also used to mitigate a substation transformer overload. The BESS is capable of other control modes, including reactive power dispatch for voltage regulation. SCE used the system to validate distribution-circuit voltage models and demonstrated the ability of a BESS to use reactive power to improve voltage on the circuit.

KEY TAKEAWAYS AND LESSONS LEARNED:

- **Location is critically important.** When it comes to BESS, it's all about location, location, location. Finding a site with appropriate characteristics (zoning, utility interconnection capacity, friendly neighbors, no existing environmental concerns, workable existing above and below-ground structures, and space for construction lay-down, interconnection facilities, the BESS, and O&M access) is difficult. Surveys for existing conditions, careful site layout, and adherence to codes and utility service requirements are critical to making busy, urban locations like this work.
- **Lack of Defined Process and Design Standards.** At the time, there was a lack of defined processes within SCE for building utility-owned, distribution-connected BESS. Various groups had to develop processes as the need arose. Today, all utility-owned, distribution-connected BESS projects follow established processes. Various technical lessons learned in the areas of system design and operation were incorporated into future BESS procurements, and they are now part of the extensive technical requirements for SCE's Energy Storage Integration Program (ESIP) projects. Examples include the ability to remotely monitor and control medium- voltage (i.e., 12 kV) circuit breakers through SCADA (Supervisory Control and Data Acquisition), more stringent cabinet-ingress protection requirements, and more flexible scheduling and control logic. There is also a lack of appropriate internal design standards in cases when the utility is the authority having jurisdiction (AHJ) and is responsible for performing its own design reviews and inspections. For this and other projects, SCE adapted utility substation and distribution design standards, the National Electric Code, and other standards from organizations, such as IEEE.

- **Strong Warranties are Valuable.** This project included a two-year, BESS warranty, which proved critical in addressing multiple PCS liquid cooling system leaks and component replacements. Several minor battery system component replacements were also covered by the warranty.
- **Grid Asset Classification Offered Different Permitting and Inspection Process.** SCE is regulated by the CPUC and is exempt from local discretionary permits. This exemption allows SCE to design, build, inspect, and maintain its own grid infrastructure on utility-controlled property without having to secure the discretionary permits and inspections that normally apply to behind-the-meter and non-grid electric facilities. Nevertheless, SCE is still required to file ministerial permits if required by the local AHJ. For DESI 1, SCE engaged the City of Orange, including the fire department, for awareness and input. SCE also employed existing utility substation and distribution design standards where appropriate and required all low-voltage BESS systems to comply with appropriate standards, including NEC. Furthermore, all BESS systems were inspected by a NETA-certified third-party and are periodically inspected and maintained per OEM recommendations.

SOUTHERN CALIFORNIA EDISON—DISTRIBUTED ENERGY STORAGE VIRTUAL POWER PLANT

stem

OVERVIEW:

- **Size and Location:** 85 MW available for up to four hours when dispatched in Western Los Angeles Basin, including parts of Orange and Los Angeles Counties
- **Challenge/Opportunity:** Long-term local capacity constraints
- **Primary Drivers:** Internal management decision; regulatory mandate
- **Technology Focus:** Artificial intelligence-driven energy storage and demand response
- **Sourcing:** Competitive solicitation, Request for Offers (RFO)
- **Utility and other key allies:** Southern California Edison (SCE) contracting Stem, Inc. (Stem)
- **Status:** Active since December 2016

SUMMARY:

Stem's Distributed Energy Storage Virtual Power Plant is one of the first large-scale deployments of customer-sited resources for a utility. Its size demonstrates NWAs potential to provide fast, reliable, and flexible resources to respond to localized grid capacity needs. SCE contracted Stem to build and operate an 85 MW virtual power plant consisting of distributed energy storage systems to contribute flexible capacity for 10 years.

CHALLENGE AND OPPORTUNITY:

SCE needed a fast, reliable, and flexible resource to address capacity needs in a highly constrained area. Also, SCE was also looking for ways to engage customers with new, value-added services.

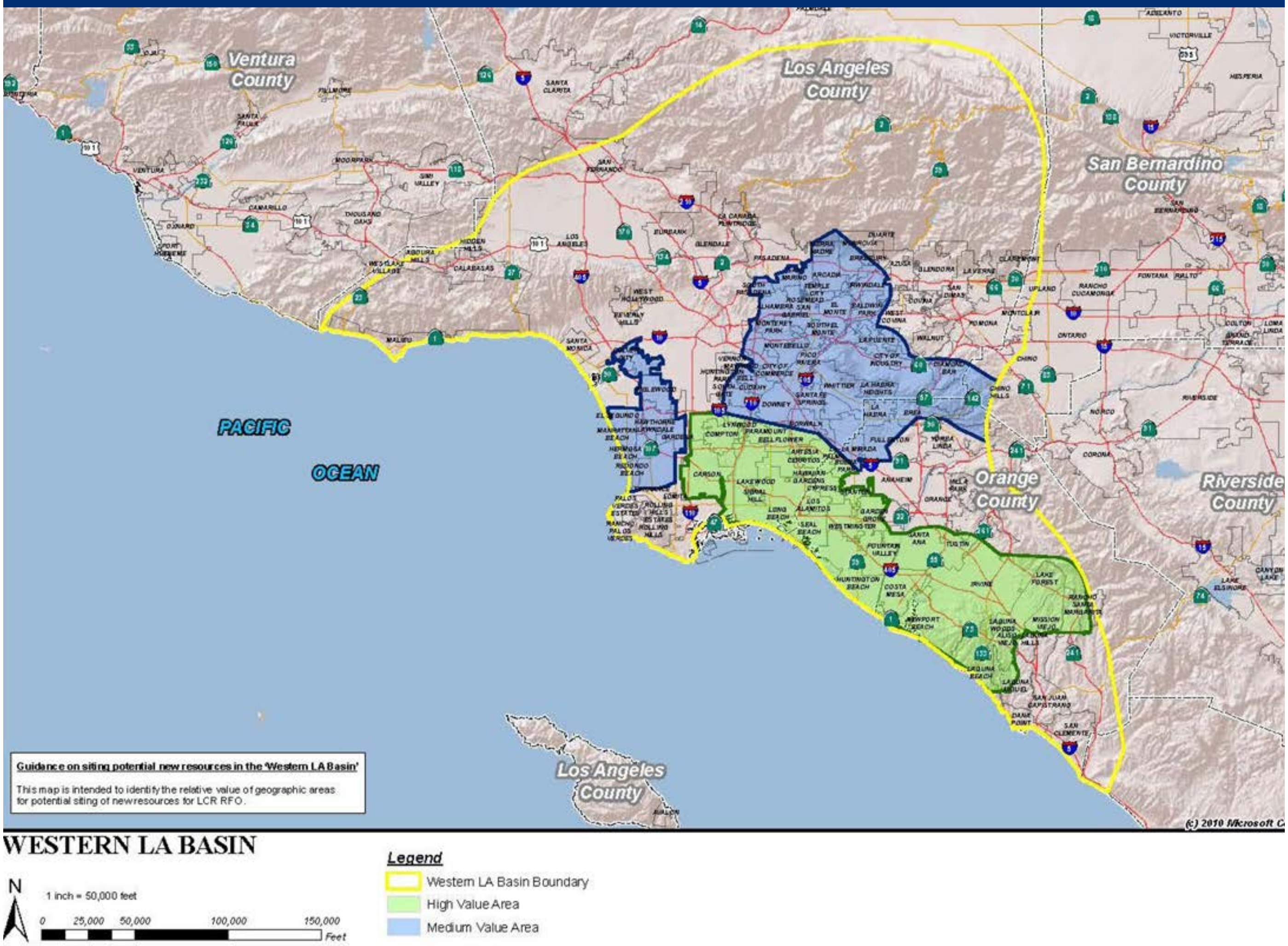
In 2013, the CPUC (the Commission) authorized SCE to procure between 1.4 and 1.8 GW of electrical capacity in the Western Los Angeles local reliability sub-area to meet long-term local capacity requirements (LCRs) by 2021. These capacity requirements resulted from the closure of the San Onofre Nuclear Generating Station and the anticipated retirement of older, natural gas generation plants along the Southern California coastline that rely on ocean water for their cooling needs. The Commission also directed that at least 150 MW of capacity be procured through preferred resources consistent with the Loading Order in the Energy Action Plan, i.e. energy storage resources. The LCR solicitation sought to integrate energy storage, energy efficiency, demand response and other preferred resources so that they could be used as local capacity in the highly-congested and transmission-constrained Western Los Angeles Basin (see figure on next page).

SOLUTION:

In 2014, SCE contracted with Stem to build and operate an 85 MW Virtual Power Plant (VPP) to meet LCR needs by contributing flexible capacity to the utility for 10 years. Through this agreement, SCE has dispatch rights to capacity from Stem's VPP. Stem's Artificial Intelligence (AI) software, Athena, directs dispatch of VPP distributed energy assets to help SCE balance the grid during critical peak times. The VPP serves as a firm, on-call dispatchable, peak-capacity resource. A dedicated subset of the project focused on two high-voltage substations (Johanna and Santiago).

The project is unique in that it leverages a cutting-edge AI platform to control and dispatch distributed energy resources on a repeatable, real-time, day-ahead and targeted geographic basis. The project demonstrates how to successfully aggregate and deploy indoor and outdoor systems featuring three types of batteries and inverters from different technology providers at multiple sites to serve a diverse set of customers and load shapes.

SITING LOCATION MAP FOR CONSTRAINED AREA, WESTERN LOS ANGELES BASIN



Source: Southern California Edison, 2018.

Stem currently has over 100 systems participating in the VPP, with many dozens more in the installation phase. Participating customers include Fortune 500 corporations, other major commercial firms, and public institutions. Stem is finding strong customer demand for energy storage services that provide energy bill savings but also offer ways to participate in the power market via grid support or other grid- and utility-facing services. Stem offers customers a long-term contract with fixed monthly subscription payments, the aim being to achieve automated savings worth two to three times the payment. Customers report being satisfied with the no-manual-intervention and no-internal-interference aspects of their participation in the VPP.

RESULTS:

Stem dispatched its fleet of distributed storage systems more than two dozen times throughout 2017, often during hours when the sun had set and solar PV systems could not be leveraged to generate electricity to offset increasing evening loads. This NWA capacity contributed to meeting critical peak capacity during 2017's unprecedented summer and fall heat waves.

The successful dispatch of capacity makes this VPP the first distributed energy resource of its kind to be integrated into any of SCE's energy portfolios. Using Stem's customer-sited energy storage to reduce customers' demand charges and improve energy bill savings—while also providing them access to new SCE programs and new grid or utility services—can be a valuable, new customer engagement tool for SCE.

Customer satisfaction results are high. Early Stem LCR customers in the VPP were recognized for using Stem's energy storage innovations in their energy management plans. In 2018, LBA Realty won the Smart Energy Decisions Innovation award and the Energy Manager Today award for its energy savings results. A 2.3 MWh, AI energy storage system was installed at LBA's Park Place facility. At the time, it may have been the largest indoor energy storage system in North America.

KEY TAKEAWAYS AND LESSONS LEARNED:

- **Strong performance.** The VPP's performance demonstrates that distributed storage assets are consistently reliable, fatigueless, fast-dispatch assets year-round on both a day-ahead and "day of" call basis. That stands in contrast to the performance of typical DR assets. VPPs can also be sited to serve precise local congestion issues and manage the variability associated with high penetrations of wholesale and distributed renewable energy.
- **Streamlined interconnection without sacrificing safety.** This project provides important lessons regarding streamlining utility interconnection and permitting of customer-sited storage without sacrificing important engineering and safety reviews. For example, SCE worked with Stem during the winter of 2018 to accept photo-based interconnection documentation for smaller, less complex installations that sped customers' access to the storage services by several weeks, while also reducing system installation costs at those sites. On the permitting front, the City of Irvine reduced its permit reviews to an average of four weeks compared to other cities that take up to several months to review permits for similar behind-the-meter resources. This helps implementation of California's new AB 546, a law that will require certain streamlining procedures for customer-sited energy storage. It also will educate local jurisdictions on best practices regarding storage permitting.
- **AI can avoid double-payment.** Using AI-enabled energy storage platforms offers greater potential for customer participation without the risk of double-payment by ratepayers. Stem captures data on a one-second basis and stores terabytes of such data to its "cloud." Metered generator output and AI controls offer the operator, utility, and policymaker new abilities to measure operational conditions and performance at more granular level as opposed to the account-level. This capability articulates which service was being performed for whom and exactly when. The project partners continue to discuss ways to assist regulators to update customer-program participation rules so that customers can increase participation in multiple customer demand response programs and access the multiple applications offered by behind-the-meter energy storage.
- **Engaging—and then satisfying—the customer is key.** This project demonstrates how SCE has successfully created more opportunities for its customers to lower their energy bills and to contribute in to a reliable, modernized grid in new ways.

TO LEARN MORE (SUPPORTING DOCUMENTATION/SOURCES):

- Attachment 1: Local Capacity Requirements Request for Offers Bidders Conference Presentation
- Attachment 2: Local Capacity Requirements Flyer
- Attachment 3: General Siting Map
- 2013 SCE LCR RFO General Information
- CPUC Decision Authorizing Long Term Procurement for Local Capacity requirements

- Rocky Mountain Institute, *The Economics of Battery Energy Storage*, October 2015.
- Lawrence Berkeley National Laboratory, *2025 California Demand Response Potential Study – Charting California's Demand Response Future: Final Report on Phase 2 Results*, March 2017. c.f.: "Fixed behind the meter battery storage is in a sense 'perfect' DR technology."