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SYSTEM RELIABILITY PROCUREMENT

2019 REPORT

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2019 SYSTEM RELIABILITY PROCUREMENT REPORT

Introduction

The Narragansett Electric Company's d/b/a National Grid (National Grid or Company) is pleased to submit this annual System Reliability Procurement Report (SRP Report) for 2019 to the Rhode Island Public Utilities Commission (PUC). The SRP Report has been developed by National Grid in collaboration with the Energy Efficiency Collaborative (the Collaborative).[1]

This SRP Report is submitted in accordance with the Least Cost Procurement law, R.I. Gen. Laws § 39-1-27.7, the basis for which is the Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006 (as amended in May 2010),[2] and the PUC's revised "System Reliability Procurement Standards," approved by the PUC in Docket No. 4443 (SRP Standards).[3] This Plan is being jointly submitted as a Stipulation and Settlement (Settlement) between the Rhode Island Division of Public Utilities and Carriers (Division), the Energy Efficiency and Resource Management Council (EERMC), Acadia Center, People's Power & Light, the Rhode Island Office of Energy Resources (OER), and National Grid (together, the Parties), and addresses a range of topics discussed by members of the Collaborative regarding the Company's SRP Report for calendar year 2019.

Section 2.1(D) of the SRP Standards requires that the Company identify transmission ~~or~~ and distribution (T&D) projects that meet certain screening criteria for potential non-

[1] Members of the Collaborative presently include the Company, the Division, TEC-RI, People's Power & Light, and Acadia Center, along with participation from the OER Office, several EERMC members, and representatives from the EERMC's Consulting Team.

[2] The Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 (the 2006 Act) provides the statutory framework for least cost procurement, including system reliability in the State of Rhode Island. The 2006 Act provided a unique opportunity for Rhode Island to identify and procure cost-effective customer-side and distributed resources with a focus on alternative solutions to the traditional supply and infrastructure options. Overtime, these alternative solutions may deliver savings to customers by deferring or avoiding distribution system investment, and improving overall system reliability.

[3] The Least Cost Procurement law, R.I. Gen. Laws § 39-1-27.7, requires standards and guidelines for "system reliability" that include the "procurement of energy supply from diverse sources," including, but not limited to, renewable energy resources, distributed generation, including but not limited to, renewable resources and cost-effective combined heat and power systems, and demand response designed to, among other things, provide local system reliability benefits through load control or using on-site generating capability. On June 10, 2014, in Docket 4443, the PUC unanimously approved revised standards for system reliability, finding that the standards were consistent with the policies and provisions of R.I. Gen. Laws 39-1-27.7.1(e)(4),(f) and R.I. Gen. Laws § 39-1-27.7.3.

wires alternative (NWA) solutions that reduce, avoid, or defer traditional T&D wires solutions. NWAs are targeted actions by customers or the utility that promote the deferral of a specific Company investment in transmission or distribution infrastructure. Section 2.1 (I) of the SRP Standards further require the Company to submit, by November 1 of each year, an SRP Report that includes, among other information, a summary of where NWAs were considered, identification of projects where NWAs were selected as a preferred solution, an implementation and funding plan for selected NWA projects, recommendations for demonstrating distribution or transmission projects for which the Company will use selected NWA reliability and capacity strategies, and the status of any previously approved NWA projects.

National Grid seeks approval of this 2019 SRP Report in accordance with the guidelines set forth in Section 2.1 of the SRP Standards.

Summary of the Company's Proposal

This 2019 SRP Report includes a review of the infrastructure projects studied for NWA potential, a discussion of the work the Company has been doing to create the Rhode Island System Data Portal (Portal) and associated marketing and engagement plan, updates on the load curtailment NWA Pilot (Pilot) in Tiverton and Little Compton, updates on the Little Compton Battery Storage Project (Project), discussion on the South County East NWA opportunities, ~~two~~ one new program proposal~~s~~, and a discussion on locational incentives in Rhode Island.

The Company is providing an update on the development and rollout of the Portal, as well as an update on the associated customer engagement and marketing campaign plan for the Portal. The marketing campaign is part of an effort to promote the Portal to potential distributed energy resource (DER) solution providers and to increase industry knowledge of the Portal and incentives available through existing Company and state programs for conservation, peak load relief, and renewable energy projects in highly-utilized areas. The Company intends to continue the marketing campaign effort for the Portal through the 2019 calendar year.

As part of this 2019 SRP Report, the Company is providing~~es~~ an update on the final evaluation of the Tiverton NWA Pilot and its scheduled conclusion, which the ~~c~~Company proposed in the 2012 System Reliability Procurement Report – Supplement (2012 SRP Report) and which ~~the~~ was subsequently approved by PUC ~~approved~~ in Docket 4296.

~~The~~ An ~~new~~ NWA project is proposed in this Report, which is ~~is~~ called the Little Compton Battery Storage Project (Project). The ~~Little Compton~~ Project~~, which~~ includes a battery storage system that will be installed in ~~Little Compton~~Tiverton, RI ~~and~~ which is capable of providing 1 MWh of energy storage at a level of 250 kW of continuous peak load relief in the areas of Tiverton and Little Compton. ~~It~~The battery storage system would operate between the hours of 3:30pm and 7:30pm during the months of June through September. Although the ~~Little Compton~~ Project is located in the same footprint as the Tiverton NWA Pilot and is intended to further defer the $2.9 Million substation upgrade detailed in the Tiverton NWA Pilot proposal in Docket 4296, the ~~Little Compton~~ Project is a separate effort from the Tiverton NWA Pilot.

Additionally, a new program is proposed in this Report, which is called the Customer-Facing Program Enhancement Study (Study). The Study will gather lessons learned and relevant research to use in development and testing of novel customer engagement approaches. These approaches will be designed to increase enrollment, participation, and retention in customer programs that can be used for demand response. The Company will carry out the Study in three phases in partnership with experts from the University of Rhode Island, with phases 1 and 2 taking place in 2019.

The Company estimates that approximately $459,300 ~~399,300~~ in incremental costs will be required in 201~~8~~9 to implement the projects and initiatives detailed in this Report. The Company is requesting recovery for these funds and a four-year commitment to the Project funding, subject to additional budget funding requests to be made in the ~~2019,~~ 2020, ~~and~~ 2021, and 2022 SRP Reports.

Consideration of NWAs in System Planning

All transmission and distribution needs continue to be screened for NWA feasibility. To determine whether an NWA solution is feasible, the Company screens traditional solution transmission and distribution projects against the criteria listed in Section 2.1(D) of the SRP Standards, which are aligned with the Company's internal planning document. There are two important distinctions in how the Company checks for NWA suitability. First, and most important, is the NWA screening and analysis that is included within comprehensive distribution planning. Within such efforts or studies, NWA screens are applied against an identified issue, opportunities are investigated to adjust one or more of the screening criteria, and partial NWA opportunities are investigated. The second NWA screen is done when the projects are initiated in the Company's project management system. All projects, including those originating for comprehensive distribution planning analysis, are ultimately included as an entry in the project management system. However, many other projects not subject to planning analysis are also created. Therefore, the Company conducts a second NWA screen on all the projects created in the management system to be sure an opportunity is not missed. The other projects can be driven by customer requests, public requirements, or created from programs such as cable replacement programs or Energy Management System (EMS) expansion programs.

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While necessary to ensure an NWA opportunity is not missed, it is typically standard practice to apply the NWA screening guidelines to these other projects.

~~when the projects are initiated. A project is initiated when a future need is identified. The timing of that future need can vary greatly from just a few years to up to twenty years. Once a future need is identified, the Company conducts a detailed analysis intended to conceptualize and compare potential wires and non-wires solutions.~~ If the Company determines that an NWA solution is feasible, ~~it~~ the NWA solution is fully developed and then proposed through the next SRP Report. If a wires solution is the best option, then that traditional solution project is fully developed and incorporated into the Company's Electric Infrastructure, Safety and Reliability Plan (ISR Plan)[4].

To determine whether an NWA solution is feasible, the Company first screens traditional solution transmission and distribution projects against the criteria listed in Section 2.1(D) of the SRP Standards, which are aligned with the Company's internal planning document. There were 48~~X~~ ~~traditional solution~~discretionary distribution projects initiated within the Company's project management system between April 1, 2017 and March 31, 2018 and all were determined to be ineligible for NWA consideration. A table detailing the projects reviewed and the reasons for their NWA ineligibility is provided in Appendix 4.

~~In addition to traditional solutions, tThe Company has included Volt-VAR Optimization and Conservation Voltage Reduction (VVO/CVR) projects in the upcoming Infrastructure Safety and Reliability (ISR) Plan. Although the main components of the VVO/CVR projects are capacitors, they are controlled in a non-traditional way that emulates an NWA effort. These projects deliver energy at a voltage level that results in a peak-time efficiency for customers, saving them an estimated 3% on their energy charges. This technology also manages reactive power flows, which reduce system loss inefficiencies and in turn, peak power flows resulting in an estimated 3% peak demand reduction. Finally, this technology provides the Company with more granular information on distribution asset performance and operations that may improve future system efficiency without the need for a specific NWA project.~~

The Company is also continuing to progress its NWA consideration in its distribution area studies, including the South County East (SCE) Area Study. The Company

[4] Notably, newly initiated projects comprise only part of the budgets and assets that are included in the Company's Electric ISR Plan, which includes all projects that will be part of the Company's capital investment portfolio in a given year, which typically includes multi-year projects that may already be in progress. Also, projects that ultimately do not pass NWA screening in a given year may not always be included in the ISR budget for that year due to a variety of constraints. Instead, these projects will be proposed as the ISR budgets allow in future years. Therefore, it is possible that there may be projects and budgets related to load growth in the ISR that are not included in the screening conducted for this Report. Once a solution is chosen for either a transmission or distribution project and is included in an annual ISR filing, it is not screened for NWA feasibility again.

identified ~~3~~ three NWA opportunities in the SCE study, in the towns of Narragansett, South Kingstown, and Exeter. The Company is actively pursuing Requests for Information (RFIs) with solution providers to test the market for NWA solutions in these areas.

Table 1~~1~~: South County East Study - NWA Analysis

Area	Load Relief	Traditional Wires Option	Traditional Wires Option
Narragansett	2.7 MW	Feeder upgrade/reconfiguration	$2.50M
South Kingstown	2.0 MW	Feeder upgrade/reconfiguration	$1.25M
Exeter	0.7 MW	Feeder upgrade	$1.50M
Total	**5.4 MW**		**$5.25M**

Additionally, the Company has some ~~is open to re-evaluating~~ NWA opportunities that were identified in past Area Studies that are pending re-evaluation.~~ for those projects that are not in past or the present year's ISR filings.~~ A specific timeline would need to be settled upon for re-evaluation.~~review, however the~~ The Company recognizes that NWA technology costs change over time, and projects that might not have been viable at the time of study ~~when compared to traditional wires projects~~ might become viable if technology costs decrease over time~~were lowered~~.

Table 2: NWA Areas to be Re-Evaluated

Study Area	Load Relief	Traditional Wires Option
East Bay	12-15 MW	Substation expansion, Feeder installation - Bristol
Providence	3.9 MW	Substation expansion, Feeder installation - Geneva
Providence	2.3 MW	Substation expansion, Feeder installation - Geneva

The Company shall also issue, by December 31, 2019, at least two new requests for proposals (RFPs) from third-party developers for the purchase of a set of NWA resources. The decision on where to locate the NWAs will be based on the information provided in the Portal, as well as on distribution area studies. The location-based avoided costs referenced in the 2018 SRP Report would be used as the maximum amount payable for NWA resources. Any contracts to procure NWAs would have to be approved by the Rhode Island PUC as required for all non-tariff contracts.

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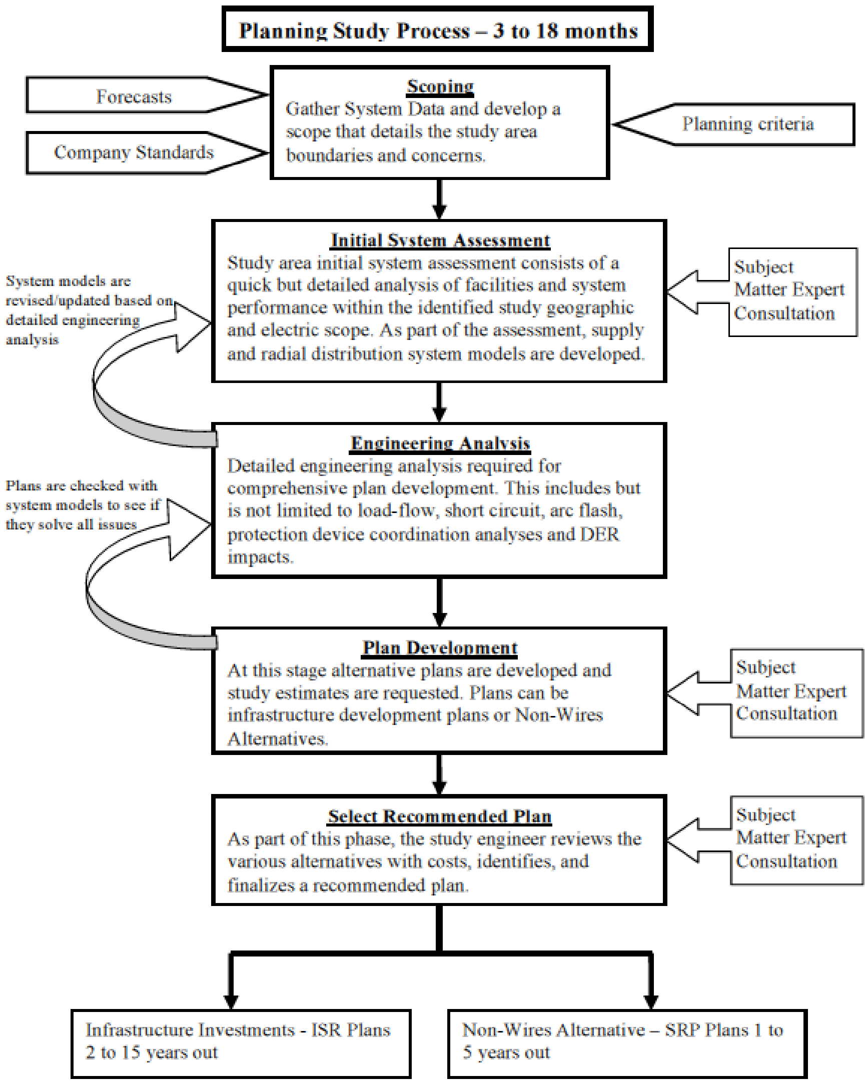
The figure ~~below~~ on the following page is a Distribution Planning Study Process flowchart, which outlines the major steps and study-based inputs in the overall area study process. The Company plans to continue analyzing its current NWA screening and development processes to determine how NWAs might be best considered as both complete and partial solutions.

Figure 1: Distribution Planning Study Process Flowchart



Rhode Island System Data Portal & Heat Map Resources

This section provides an update for thise RI SRP 2019 Plan~~2019 SRP proposal docket~~ regarding the Rhode Island System Data Portal and associated resources.

The 2018 SRP docket proposed the ~~beginning~~ initial work on the Rhode Island System Data Portal. Future work and costs related to~~work on~~ the Portal is~~willis be~~ included in the current rate case~~s~~ under Docket 4770. The initial version of the Portal went live on June 30th, 2018. ~~This~~ The Portal include~~sd~~s:

1. Company Reports~~ Information~~
   a. Distribution Planning Study Process
   b. Distribution Planning Criteria
   c. 2018 Electric Peak (MW) Forecast
   d. Electric Infrastructure, Safety and Reliability (ISR) FY 2019 Proposal
   ~~1.~~e. 2018 System Reliability Procurement (SRP) Report

2. Distribution Assets Overview
   a. Specific Distribution Feeder and Substation Information (Feeder ID, operating voltage, etc.)
   b. Summer Normal Rating
   c. 2017 Recorded ~~l~~Loading, and ~~f~~Forecasted ~~l~~Loading to 2027~~.~~

3. Heat Map
   a. An interactive color coded map of Distribution Feeders based on 2018 forecasted load compared to Summer Normal Rating~~. This~~
   ~~a.~~b. ~~p~~Provides information on circuits that would benefit from DER interconnection for load relief, and on circuits that have existing capacity for load projects, like charging stations, heat pumps, etc.

4. Hosting Capacity
   ~~4.~~a. The Hosting Capacity Map is ~~(~~ still under development with a planned go-live date of September 30th, -2018~~)~~
   ~~a.~~b. Substation ground fault overvoltage protection (3V0) status; ~~(~~installed or not, if 3V0 is in construction or slated for construction, and the proposed in service date~~)~~
   ~~b.~~c. Distribution Feeder interconnected and in-~~ ~~process Distribution Generation amounts

The Company is continuing to finalize the Hosting Capacity interactive map for the Data Portal. This requires additional modeling and analysis for color coding of feeders based on maximum Hosting Capacity.

~~As mentioned above, the Company is actively pursuing three NWAs, in the towns of Narragansett, South Kingstown and Exeter.~~

~~Additionally, the Company is open to re-evaluating NWA opportunities that were identified in past Area Studies. A specific timeline would need to be settled upon for re-review, however the Company recognizes that NWA technology costs change over time, and projects that might not have been viable when compared to traditional wires projects might become viable if technology costs were lowered.~~

Market Engagement with NWAs

The Parties agree that there may continue to be additional opportunities for installations of technologies that reduce peak load outside of the Company's consideration~~ and proposal of cost-effective NWA projects~~. To nurture these inherent opportunities with the work the Company is doing on the Portal, and to encourage DER solution providers to support the strategic deployment of these solutions to benefit constrained areas, the Company proposes to continue to develop and deploy a marketing and engagement plan in 2019. The plan will build on the results of the 2018 plan.

Th~~is~~e proposed marketing and engagement plan would promote the Portal and heat map resources described in the previous section, and~~ as they become available. The marketing and engagement plan would also~~ promote incentives already available through existing Company and state programs (e.g. net metering, Re-growth, and the ConnectedSolutions Demand Response program).

By March 31, 2019 the Company ~~would~~ will develop and share with the Parties the marketing and engagement plan with proposed tracking mechanisms to capture its effectiveness. The 2019 marketing and engagement plan is a continuation of the already live 2018 marketing and engagement plan ~~The Company will work with the Parties over the next two months to finalize the tracking mechanisms.~~

Customer Engagement Funding Plan

The Company proposes a ~~similar~~ budget similar to 2018 of $124,800 to support this initiative in 2019. The Company ~~would use~~proposes $80,000 to support the creation and dissemination of marketing materials and tracking mechanisms, and~~. The Company would use~~ $44,800 to support administrative costs associated with managing the development of the materials within the Company and with vendors, as well as managing the~~to develop~~ tracking and evaluation processes to determine the initiative's effectiveness.

Forecasted Load Growth for NWA Opportunities

This section provides an overview and update on forecasted load growth for areas in Rhode Island that have potential NWA opportunities.

Forecasted Load Growth in the Tiverton Area

The Company's distribution system serves close to 500,000 electric customers in 38 cities and towns in Rhode Island. The residential class accounts for approximately 41% of the Company's total Rhode Island load, the commercial class accounts for approximately 49%, and the industrial class accounts for approximately 10%.

The Tiverton and Little Compton annual weather-adjusted summer peaks are expected to increase at average annual growth rates of 0.3% and 0.1% respectively for the next 10 years, which are both greater rates than the statewide average annual growth of -0.2%.

The forecasted load growth rates for cities and towns in Rhode Island are shown in Appendix 1.

Tiverton NWA Pilot

In accordance with the scheduled plan and as proposed in the 2018 SRP Report, the Tiverton NWA Pilot ended on December 31, 2017. The following sections include ~~the most updated information about~~ updates on the Pilot since the 2018 SRP Report was filed in Docket 4756. This information is included here ~~both~~ in keeping with the reporting seen in past SRP Reports, as well as ~~and~~ to help clarify the reasons the Company is not proposing to extend the Pilot beyond 2017.

Implementation

The following sections provide details on the implementation of the Pilot's most recently completed year of activities and a progress report on the current year's activities to date. For more information regarding the implementation activities in previous years, please review past SRP Reports.

2017 Summary

In 2017, the Company proposed a plan to ~~create the remaining~~achieve additional annual peak savings in order to achieve its 1 MW reduction ~~per year~~ goal. The plan entailed decreasing the focus on the targeted Energy Efficiency (EE) and Demand Response (DR) efforts and increasing focus on a market-based solution procured through ~~an~~ a Request for Proposal (RFP) process. ~~However, t~~The incentives offered in 2016 continued to be marketed and made available for customers in 2017.

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The 2017 campaign included a kickoff newsletter and series of direct mailings that contained information designed to increase customer understanding of how demand response events work and to comprehensively describe ~~fully~~ ~~comprehending~~ ~~describing~~ the benefits of the Pilot's EE and DR measures to the entire community. As in previous years, the communications were crafted to deliver different messages to ~~both~~ Pilot Participants (those previously engaged in any level of Pilot energy-saving activity) and to Non-Participants.

Additionally, in August 2017, the Company explored native ads on Facebook that directly targeted customers in the towns of Little Compton and Tiverton ~~directly~~. These ads featured the DemandLink messaging and were designed to create more awareness to support direct mail outreach.

As was the case in previous years, all marketing components in 2017 have directed customers to make contact via the online email form, centralized toll-free phone number or email to learn more about the program and sign up. RAM Marketing received these calls and emails~~, and then~~ , pre-qualified interested customers, and sent the resulting leads to RISE Engineering for scheduling. Pre-qualification consist~~s~~eds of verifying the customer's address and account on the Pilot area list, ascertaining the existence of broadband internet/Wi-Fi and either central or window AC units, and determining customer interest in each rebate.

~~To date, o~~Outreach to Pilot customers in 2017 ~~has~~ produced ~~179~~ 224 pre-qualified leads for the enhanced DemandLink incentives compared with ~~215~~ 428 leads for the same period in 2016, and ~~435~~ 730 leads in 2015.

Table 3~~2~~: Penetration of Interested Pilot Leads 2018~~7~~

Pilot Year (through month)	Leads Generated	Customer Penetration*
2012 (December)	209	4.2%
2013 (December)	1061	21.3%
2014 (December)	655	13.2%
2015 (December)	730	14.7%
2016 (December)	428	8.6%
2017 (~~August~~December)	~~179~~224	~~3.6%~~4.5%
Total through ~~August 17~~December 31, 2017	**~~3257~~3,302**	**~~65.6%~~66.5%**

**** Based on total of 4970 available Pilot customer phone numbers***

The number of qualified leads for measures other than the EnergyWise home energy assessments was much lower than in previous years during the same time period. The

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Company believes that this is due in part to the fact that the Pilot reaches a saturation point with customers who respond to telemarketing.

To close out the remainder of ~~this year~~2017, the ~~c~~Company ~~will make~~made another ~~aggressive~~ active push to engage as many eligible customers as possible to participate~~create as much participation as possible~~. This push ~~will~~ included a second telemarketing pass, direct mail, social media, and email marketing.

Twenty-three DR events were initiated from July through September 2017[5]. Approximately half of these events were triggered by a forecasted need on the feeder, while the rest were triggered based on weather conditions. Preliminary event data from the Pilot's demand response management system (DRMS) provider, Whisker Labs, indicates that approximately 60-65% of thermostats ~~are~~ fully participate~~ing~~ in the event. ~~Six~~ Eight to ten~~eight~~ percent (8-10%) of thermostats opt out while the event is in progress, and approximately 27% ~~are~~ opt~~ing~~ out either prior to the event set points going live or ~~were~~ are not in cooling mode when the event ~~was~~ is triggered.

In late 2016, the Company began a solicitation process to procure a peak-shaving solution from the market. The ~~Request for Proposals (~~RFP~~)~~ was released in November, and the process concluded in January with a successful bid for a battery storage project. The Company worked diligently with the chosen vendor throughout 2016 to position the battery for service by the end of the year. However, due to delays in equipment selection affecting the interconnection process, the project's timeline has been pushed out into ~~2018~~2019. In recognition of the timeline associated with the Pilot and the value of implementing this energy storage project, the Company is proposing to ~~split~~ separate this battery storage effort from~~out of~~ the Pilot and promote the battery storage effort as its own NWA project proposal, the Little Compton Battery Storage Project. Details of this ~~new~~ proposal are given in later sections of this Report.

Regarding participation and kW savings metrics, please refer to the National Grid Rhode Island System Reliability Procurement Pilot: 2012-2017 Summary Report in Appendix 3.

In accordance with the scheduled plan and as proposed in the 2018 SRP Report, the Tiverton NWA Pilot ended on December 31, 2017.

Final Closeout of Pilot

With the conclusion of the Pilot ~~finished~~ at the end of the 2017 calendar year, the only remaining activities for the 2018 calendar year are the final evaluation ~~of the Pilot~~ and the final notification to customers~~ of Pilot completion~~.

[5] There were no events triggered in June 2017 due to mild weather conditions.

The final notification to customers of the Pilot's completion occurred on June 5, 2018 via email. The email notification was sent to all customers participating in the Pilot that had email addresses still subscribed for the Company's notifications. All customers participating in the DemandLink demand response program of the Tiverton NWA Pilot have been automatically enrolled in the ConnectedSolutions program to allow them to continue participating in demand response events. Email services and metrics were provided by Questline.

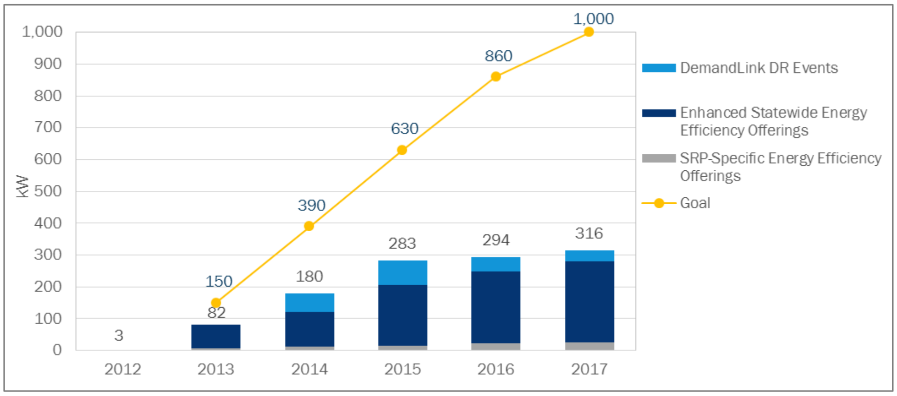
The final evaluation of the Pilot is described in the Evaluation section that follows.

Evaluation

A final evaluation of DemandLink, National Grid's load curtailment pilot (Pilot), ~~DemandLink,~~ in Tiverton and Little Compton Rhode Island was completed in July 2018 by Opinion Dynamics Corporation (ODC). The final evaluation report is included in Appendix ~~__.~~ 3. The final evaluation examined the effectiveness of each of the strategies employed by the Company to deliver 1 MW of load relief by 2017 (the last year of the pilot) to defer the new substation feeder for 4 years, from 2014 to 2018. These strategies included (1) implementation of the DemandLink Programmable Controllable Thermostat Program, (2) enhancement of existing statewide energy efficiency offerings, and (3) introduction of new SRP-specific energy efficiency offerings.

The final impact evaluation found that the Pilot fell short of its 1 MW load reduction goal. However, the Pilot's initial progress postponed the investment of the wires alternative that would have occurred in 2014, if not earlier. The investment in the substation upgrade was further deferred due to slower than expected load growth and cooler summer temperatures in 2017.

Figure 2: Cumulative Load Impacts (kW) Compared to Goal



The evaluation found that the EnergyWise and Small Business Direct Install programs were the largest contributors to total load impacts, with 152 kW (48% of the total) and 96 kW (31% of the total), respectively. Demand response events accounted for 36 kW (11% of the total).

Key Findings and Recommendations

The final evaluation provided the following key findings and recommendation for any future program offerings.

1. Demand Response

   The Pilot resulted in lower than expected savings from residential demand response events. The evaluation found three main ~~challenges~~ contributing factors to this outcome: (1) low enrollment in the program; (2) significant connectivity issues, especially for participants with window AC; and (3) an event strategy that resulted in lower than expected hourly per household event savings.

Table ~~4~~5: Summary of Demand Response Impacts

Program Year	# of Events	Per-Thermostat Impact		Mean # of Thermostats in Analysis[b]	Program Impact (kW)
		Runtime Reduction	kW[a]		
Central AC					
2014	3	8.6%	0.32	176	56
2015	15	13.3%	0.49	155	76
2016	18	10.9%	0.40	115	46
2017	15	14.8%	0.52	68	36
Window AC					
2014	3	n/a	0.07	28	2.0
2015	15	n/a	0.04	14	0.6
2016	15	n/a	0.045[c]	0.4	0.018
2017	n/a				

In addition to the key findings, t~~T~~he evaluation provided several recommendations for the Company to consider in future demand response programs:

1. Future programs should not rely on equipment that requires customer action or reinstallation each year. The window AC plug devices used in the Pilot were discontinued in 2016 due to significant connectivity issues and misuse by customers.

2. Deploy the following changes to the demand response strategy to increase the savings per thermostat:
    a. Deploy a more aggressive offset strategy for events (ex. 3°F or 4°F set point) or consider cycling of the unit instead.
    b. Maintain the event length at 3 hours to avoid negative savings in the last hour of the event.
    c. Consider precooling before event.
    d. Only call events when peak demand is predicted.

3. Conduct additional testing of central AC thermostats to confirm connectivity before events begin.

2. Enhancement of existing statewide energy efficiency offerings

    National Grid's enhancement of existing statewide offerings was the most successful component of the pilot, contributing 255 kW, or 81%, to total pilot load impacts. There were two main limitations to this strategy reaching 100% of its goal. First, lighting measures accounted for the vast majority of the savings in the EnergyWise Program. While these measures contributed significantly to the savings in the early years of the pilot, the changing baseline for residential lighting measures (due to EISA standards) resulted in decreased savings from these measures over time. The second barrier was the determination that it was too costly to obtain the needed participation in the small business sector that caused the Pilot to capture the full potential for savings from this population of customers.

The evaluation recommends that targeted energy efficiency continue~~d~~ to be utilized in future initiatives. However, the Company should diversify away from lighting measures and consider new outreach channels to reach small commercial customers.

3. Pilot-specific energy efficiency offerings

The Company deployed two Pilot-specific energy efficiency offerings – rebates for new energy efficiency window AC units and window AC recycling. Overall, these new rebates generated 25.2 kW in peak load reductions (8% of pilot totals). The majority of these impacts came from recycling inefficient window AC units ~~without~~ and not replacing them with a new unit. The evaluation determined that the largest barrier to this strategy's success was ~~due to~~ lack of customer awareness. Only 38% of eligible customers were aware of these offerings.

The evaluation determined there are still significant savings opportunities for these measures in the Pilot area. ~~Almost~~ Approximately 4 out of 10 customers in the Pilot area indicated they used or planned to use window AC to cool their home in the summer. In addition, 19% of customers had window AC units that they no longer used or that they were thinking about replacing in 2017. In order to reach these customers, the evaluation recommends that any future efforts should deploy more focused outreach on these two measures and consider offering time-limited enhanced rebates to increase participation.

With the end of the Pilot and the planned battery storage pilot, it no longer makes sense to deploy the window AC rebate and recycling measures as a deferral strategy. However, the recommendations and results of the evaluation for these measures will be considered by the Energy Efficiency strategy team for any future offerings to coastal communities, as well as to other future initiatives.

The Company plans to apply the results of this evaluation and the lessons learned over the course of the Pilot to future initiatives. While the Pilot did not meet its 1 MW reduction goal, the Company gained valuable insight into customer behavior, marketing effectiveness, and demand response strategies that will help improve customer offerings in the future.

Pilot Benefit Cost Analysis

The benefit cost calculations for this pilot have been completed using the Total Resource Cost test.[6] Figures for pilot years 2012 through 2018~~7~~ have been updated to reflect actual results, year-end projections and data from the EE impact evaluation, as applicable.

[6] For a detailed description of the cost and benefits associated with the cost-effectiveness framework, see 2012 SRP Report - Supplement, February 1, 2012, Docket 4296.

Table S-2: Summary of Cost Effectiveness for Tiverton NWA Pilot

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Table S-2
System Reliability Procurement - 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[1]	$90.2	$1,015.1	$716.7	$1,024.8	$435.0	$66.94	$0.0	$3,348.7
SRP Energy Efficiency Benefits[2]	$88.8	$310.4	$136.8	$78.0	$88.1	$341.6	$0.0	$1,043.7
Demand Reduction Benefits[3]	$0.0	$0.0	$5.6	$6.8	$5.3	$11.3	$0.0	$28.9
Deferral Benefits[4]	$0.0	$0.0	$174.2	$171.5	$159.4	$148.2	$0.0	$653.3
Costs	**$133.4**	**$672.4**	**$569.3**	**$1,029.4**	**$611.1**	**$510.9**	**$90.8**	**$3,617.4**
Focused Energy Efficiency Costs[5]	$46.6	$331.1	$195.8	$529.3	$280.1	$281.3	$0.0	$1,664.1
System Reliability Procurement Costs[6,7]	$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:

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

(2) SRP EE benefits include all TRC benefits associated with EE measures installed in each year that would not have been installed as part of the statewide EE programs.

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

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

(5) 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 programs. These are the programs through which measures in this SRP pilot will be offered.

(6) 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.

(7) All costs and benefits are in $current year except for deferral benefits.

(8) 2012-2017 numbers have been updated to reflect year end data. 2018 numbers reflect year end projections.

Table S-2
System Reliability Procurement - Tiverton/Little Compton
Summary of Cost Effectiveness ($000)

	2012	2013	2014	2015	2016	2017	Overall
Benefits	**$179.0**	**$1,325.4**	**$1,033.3**	**$1,281.1**	**$687.7**	**$668.5**	**$5,175.0**
Focused Energy Efficiency Benefits[1]	$90.2	$1,015.1	$716.7	$1,024.8	$435.0	$497.6	$3,779.4
SRP Energy Efficiency Benefits[2]	$88.8	$310.4	$136.8	$78.0	$88.1	$11.3	$713.3
Demand Reduction Benefits[3]	$0.0	$0.0	$5.6	$6.8	$5.3	$11.4	$29.0
Deferral Benefits[4]	$0.0	$0.0	$174.2	$171.5	$159.4	$148.2	$653.3
Costs	**$133.4**	**$672.4**	**$569.3**	**$1,029.4**	**$611.1**	**$1,122.6**	**$4,138.3**
Focused Energy Efficiency Costs[5]	$46.6	$331.1	$195.8	$529.3	$280.1	$804.0	$2,186.9
System Reliability Procurement Costs[6,7]	$86.8	$341.3	$373.5	$500.2	$331.0	$318.6	$1,951.5
Benefit/Cost Ratio	**1.34**	**1.97**	**1.81**	**1.24**	**1.13**	**0.60**	**1.25**

Notes:

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

(2) SRP EE benefits include all TRC benefits associated with EE measures installed in each year that would not have been installed as part of the statewide EE programs.

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

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

(5) 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 programs. These are the programs through which measures in this SRP pilot will be offered.

(6) 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.

(7) All costs and benefits are in $current year except for deferral benefits.

(8) 2012-2016 numbers have been updated to reflect year end data. 2017 numbers reflect year end projections.

The Pilot remains cost effective over its life, with a benefit/cost ratio of 1.40~~25~~ as shown in Table S-2 above. Each year is also cost effective on its own, aside from 2018 which has been previously designated for final post-Pilot evaluation.~~ except for 2017. The biggest impact on the 2017 BC ratio is in the RFP solution not coming to fruition.~~

All costs and benefits in this analysis are in current year dollars, meaning that the avoided costs are inflated for each year. The savings associated with this Pilot are categorized in the same way as the benefits. These savings are shown in Table S-4 of Appendix 2. As projected, the Pilot has created over $5 million in benefits in the Tiverton/Little Compton area over its six-year lifetime. For each $1 invested, this Pilot created $1.~~25~~ 40 of economic benefits over the lifetime of the six-year investment.

Coordination with SRP Solar DG Pilot

Between 2015 and 2017, the Office of Energy Resources (OER) in coordination with National Grid conducted a pilot program to understand the feasibility and practicality of using solar PV distributed generation (DG) to reduce peak load in the towns of Tiverton and Little Compton sufficiently to defer system upgrades (referred to as the Solar DG Pilot). Through targeted Solarize campaigns and other outreach, 57 residential and 1 commercial-scale customer installed 649 kW of aggregate solar capacity. Importantly, the pilot used incentives to encourage participants to install westward-facing solar systems to better align the timing of PV output with peak demand.

The Solar DG Pilot was evaluated in its entirety by an independent evaluation in 2018, which included an impact evaluation of aligning DG with peak demand and a process evaluation of program delivery and customer perspectives. The Solar DG Pilot evaluation report[7] may be found on the OER website[8]. Evaluators found the incentive structure, while confusing, did promote adoption of westward-facing solar systems, which increased peak PV output. However, maximum electric system peak demand~~s~~ occurred later in the day than peak PV output, limiting the effectiveness of solar DG in reducing peak loads on the feeders. Ultimately, the installed capacity through the pilot did not achieve the 250-kW peak load reduction target. Lessons learned from the Solar DG Pilot will inform future consideration of solar DG as a mechanism for reducing peak load as well as program delivery, implementation, and incentive structure for solar DG as a component of future NWA projects.

[7] Shaw, Shawn, et al. *System Reliability Procurement Distributed Generation Pilot Evaluation Report*. Rhode Island Office of Energy Resources, 2018, *System Reliability Procurement Distributed Generation Pilot Evaluation Report*, www.energy.ri.gov/documents/SRP/2018-srp-dg-pilot-emv-final-report.pdf.
[8] "The OER System Reliability Procurement Solar DG Pilot Project." *State of Rhode Island: Office of Energy Resources*, Rhode Island Office of Energy Resources, 2018, www.energy.ri.gov/electric-gas/future-grid/oer-system-reliability-solar.php.

Commented [CM4]: Section also existed in last year's SRP 2018 Plan, text overhaul to reflect status and info for current year SRP 2019 Plan

Little Compton Battery Storage Project

Commented [CM5]: Section similar to last year's SRP 2018 Plan, updated to reflect status and info for current year SRP 2019 Plan

Project Proposal

For ~~2018~~2019, the Company proposes the Little Compton Battery Storage Project (Project), which will include a battery storage system to be installed in ~~Little Compton~~Tiverton, RI to provide peak load relief. The storage system will be capable of providing 250 kW of continuous peak load relief in the areas of Tiverton and Little Compton between the hours of 3:30pm and 7:30pm during the months of June through September.

The Project would provide load relief in the same geographical footprint as, and is the successor NWA project to, the Tiverton NWA Pilot. A request for proposals (RFP) solicitation for an integrated NWA solution ~~The RFP~~ was previously approved within the 2017 SRP Report in Docket 4655 as part of the Tiverton NWA Pilot. The Company completed the RFP in early 2017, resulting in a battery storage project as the winning bid. However, during the process of implementation, the project was delayed and could not be installed by the summer of 2017 as planned. It was again proposed in the 2018 plan, but due to unforeseen delays in construction scheduling and equipment availability, it was not installed and operable for the summer of 2018. Currently the project is still being worked on and details being documented in order to move forward with the installation later in 2018 or early 2019 to be operable for the summer of 2019. As a result of these delays, the Company is proposing the Project as an independent effort in 2019.~~As a result of this delay and for the reasons described in the 2018 Pilot Proposal section of this report, the Company is proposing the Project as an independent effort in 2018.~~

The battery vendor proposes to engineer, procure, construct, and install a 1 MWh advanced battery storage solution (the "Battery") designed to deliver 250 kW of peak load relief for 4 hours. The Battery ~~that~~ would be located at the ~~Little Compton Town Transfer Station, at the intersection of Colebrook Road and Amy Hart Path in Little Compton, RI~~Tiverton Public Works Facility on Industrial Drive in Tiverton, RI. The Town of ~~Little Compton~~Tiverton has provided a letter of support to the vendor for this project proposal.

The vendor's proposal is to site, own and operate the energy storage asset, and enter into a services contract to provide the required load reduction benefit to ~~National Grid~~the Company during the summers of ~~20198~~2019 through ~~20221~~2022. The Company proposes that the Project timeline span these four years, which is the maximum amount of time the substation upgrade can be deferred with this solution, based on the current peak load forecast. The Company requests commitment for this Project for that timeframe in order to enable a cost-effective agreement with the vendor for peak load relief services. However, the Company will make budget funding requests in each individual year, following the precedent set by the Pilot.

The Company shall have the Little Compton Battery Storage system online and operational by June 1, 2019.

If the Little Compton Project is not implemented, the Company would start the engineering and design of the wires solution in 2019 (ISR Plan fiscal year 2020) with construction in 2020 (ISR Plan fiscal year 2021).

Project Funding Plan

The Company estimates that it will require an initial $109,500 to implement the Project in ~~2018~~ 2019 and additional similar funds for each of the three years following. $87,500 is associated with the actual implementation of the solution, (i.e. payments to the vendor,) and $22,000 is associated with the management of that vendor in both implementing the solution and monitoring and evaluating it. Similar funding requests for the second, third, and fourth years of this Project will be proposed in the ~~2019,~~ 2020, ~~and~~ 2021, and 2022 SRP Reports.

Evaluation

The Company is proposing to evaluate the energy savings that the Project provides through a metering and control system, and the data made available through it provided by the vendor. The Company proposes that the calculation of ‘energy savings’[9] ~~(batteries have inherent losses, but the anticipation is that the battery will charge during lower wholesale price periods and discharge at higher wholesale priced hours, with the ‘savings’ being the difference in these prices) shall~~~~will~~shall be ~~measured by~~ based on the amount of power output provided by the battery storage system during peak period ~~windows over time~~ s each~~by the battery storage system per~~ calendar year.

Benefit Cost Analysis

The Project’s costs and savings were evaluated using the Rhode Island (RI) Test to determine whether the benefits of implementing the Project outweigh the costs.

The Company estimates that a four-year deferral will have approximately $905,197~~647,599~~ of localized distribution investment savings for customers[10]. This value is determined by calculating the amount of revenue requirement that will not be collected if the investment is deferred for those four years. This benefit was inserted into

[9] Note that batteries have inherent losses, but the anticipation is that the battery will charge during lower wholesale price periods and discharge at higher wholesale priced hours, with the ‘savings’ being the difference in these prices.

[10] The substation upgrade was originally planned for 2014, so all benefits for this project were inflated to $~~2018~~ 2019 to match the proposed NWA Project budget.

the RI Test model as a replacement for the regional distribution benefit in the avoided costs.

The remaining benefits were estimated using the RI Test model, assuming the 250kW reduction for four hours at a time, for an estimated twenty days per year. The number of days was estimated based on the average number of days that demand response events were called in the Pilot each year for 2015 through 2017. This benefit cost analysis differs slightly from the analysis used for the Pilot in that it uses the benefits outlined in the RI Test. The Pilot benefit-cost analysis used the Total Resource Cost test. The Project's benefit cost analysis is also consistent with the language in the SRP Standards section 2.3.F.

The Project budget of $438,000 represents the projected costs to procure load reduction services through the battery storage unit for a four-hour period for a contract of four years, as well as some Company resources to support the development and maintenance of this contract and load reduction events as necessary.

The following table illustrates the benefit-cost analysis of the Project using the RI Test. With a positive BC Ratio, this project represents a cost~~-~~-effective solution for customers.

Table 8: Little Compton Battery Storage Project Benefit-Cost Summary

Little Compton Battery Storage Project	
Total Cost	$438,000
Total Benefits	$1,004,816~~721,326~~
Net Benefits	$566,816~~283,326~~
BC Ratio	2.29~~1.65~~

South County East NWA Projects

As mentioned in the Consideration of NWAs in System Planning section, the Company is currently pursuing 3 potential NWA opportunities identified in the South County East (SCE) Area Study. These NWA opportunities are in the towns of Narragansett, South Kingstown, and Exeter.

The Company is currently engaged with the Requests for Information (RFI) process with solution providers to test the market for NWA solutions in these areas. The Company will then progress to the Requests for Proposals (RFP) stage for project bids from solution providers as planned. The Company anticipates receiving RFP responses in the

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first quarter of 2019. The Company shall select winning bids for Narragansett, South Kingstown, and Exeter by June 30, 2019.

Projects Funding Plan

The Company estimates that it will require $50,000 to evaluate the RFP responses from solution providers.

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Customer-Facing Program Enhancement ~~Pilot~~Study

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The objective of the Customer-Facing Program Enhancement ~~Pilot~~Study is to evaluate and test behavioral economic approaches to incentivize customer behavior that can be used to address electrical distribution-level constraints and improve environmental, economic, and grid performance outcomes from residential and small commercial (R&SC) customer-facing programs.

The purpose of the proposed Study is to develop a long-term program for Rhode Island that will employ low-cost and easy-to-deploy methods to address distribution-level constraints. The Company plans to integrate learnings from the Study in future programs and projects that engage customers in Rhode Island.

Background

Connected devices, such as Wi-Fi thermostats, and home automation ~~in general~~ use connectivity, sensing, and controls to provide consumer benefits, such as enhanced comfort, control, convenience, and security, which are driving a rapid increase in adoption of these devices.[11,12,13] In addition, data from connected devices can enable new energy savings opportunities, such as equipment or appliance control and performance diagnostics. Home automation concepts have existed for decades, yet until recently have achieved limited U.S. adoption. As internet access, wireless connectivity, and smartphone ownership have become ubiquitous in the last decade, many new connected devices (the "Internet of Things") have come to market, and their growth is projected to continue.[14] New technologies and better energy management capabilities could further increase adoption, particularly as time-varying electric rates become more common. However, the actual energy savings from these devices can vary widely because, in most cases, users must be motivated to save energy, or at least be tolerant of the energy-saving features, to realize significant benefits.[15]

[11] Parks Associates and the Consumer Electronics Association, "Smart Home Ecosystem: IoT and Consumers", 2014
[12] Icontrol Networks, "2015 State of the Smart Home Report", 2015
[13] St. John, J., "The Connected Home: Reaching Critical Mass for the Grid?", Greentech Media, May 2015
[14] Consumer Technology Association, "U.S. Consumer Technology Sales and Forecasts", January 2016
[15] Urban, B., Roth, K., Harbor, C., "Energy Savings from Five Home Automation Technologies: A Scoping Study of Technical Potential", Fraunhofer USA Center for Sustainable Energy Systems, April 2016

Beyond energy savings, connected devices offer households the opportunity to participate in utility demand response (DR) programs. For example, the 2014 San Diego Gas and Electric residential peak time rebate program rewarded customers for reducing energy consumption through manual or automatic means.[16] Automatic curtailment provided an incentive of $1.25/kWh avoided, compared with $0.75/kWh for manual reductions prompted by day-ahead notifications. For the 4,000 customers participating in automated reductions, ~~E~~ecobee thermostats were provided and used to curtail load for four-hour periods by duty cycling central air conditioners at 50% or by implementing a 4°F setback during the same period. Consistent with other connected thermostat pilots, the average event hour load reduction was about 0.5 kW per participant. Similar demand reductions were identified by the 2011 SMUD Residential Summer Solutions Study, which compared the impacts of assorted dynamic pricing, automatic load control, and energy feedback strategies.[17]

In addition to connected devices and home automation, traditional EE programs~~,~~ like LED replacement programs, and newer programs like connected residential energy storage and behavioral demand response, also have ~~been shown to be~~great potential to reduce~~ effective at reducing~~ peak demand. However, many of these programs have been optimized for overall energy savings rather than demand response, while others are still in the early stages of customer adoption, and most~~, and~~ have not ~~typically~~ been optimized and deployed to specifically address ~~a~~ distribution-level constraints.

~~Motivation~~

Despite their great potential, ~~many DR~~ existing R&SC customer programs ~~targeting R&SC customers~~ have struggled to achieve the level of customer enrollment, participation, and retention necessary to be effective DR tools for the utility, especially as a means to reduce peak demand to address critical distribution-level constraints. Also, the cost-effectiveness of these programs has been relatively poor when they are required to reduce a significant faction of peak load in a given area, because marketing and/or incentive budgets are often increased to try to breakthrough to non-ado~~a~~pte~~o~~rs. There have been attempts by utilities to use R&SC customer DR and EE programs to address distribution-level constraints in the past with mixed success, including the Company's DemandLink™ ~~Pilot~~ program in Tiverton, Rhode Island from 2014-2017. In the final

[16] Hanna, D., Elliot, C., and Jiang, G., "2014 impact evaluation of San Diego Gas and Electric's residential peak time rebate and small customer technology deployment programs", Itron, Prepared for San Diego Gas and Electric, April 2014

[17] Herter, K., Wood, V., and Blozis, S., "The effects of combining dynamic pricing, AC load control, and real-time energy feedback: SMUD's 2011 Residential Summer Solutions Study", *Energy Efficiency*, 6:641-653, 2013

year of the Tiverton NWA P~~p~~ilot, the Company was only able to demonstrate 36 kW in customer DR load relief and a total of 316 kW in load relief using a combination of customer EE and DR measures, while the ~~p~~Pilot's total load relief goal was 1 MW. There were ~~a number of~~several reasons the ~~DemandLink~~ Pilot underperformed, but customer enrollment, participation, and retention were identified as key challenges. Specific barriers to participation included customers' perceptions that they do not use ~~air conditioning~~appliances enough to benefit from the program and customer's comfort level with someone else controlling their ~~thermostat~~appliances. Further information on the DemandLink Pilot results are contained within the Tiverton NWA Pilot Evaluation section.

~~Customer Engagement Study~~~~As additional background~~As additional background, NWA procurements for the Company's New York affiliate, Niagara Mohawk Power Corporation (NMPC), which are similar in value to the Company's RI NWA opportunities, have struggled to procure NWA solutions that can reliably address the distribution-level constraints in a cost-effective manner as determined by the Commission's Benefit Cost Analysis (BCA) Framework. Out of the first five NWA solicitations completed by NMPC, none have resulted in a successful NWA project to date due to very low benefit-to-cost ratios under the Societal Cost Test (SCT), although NMPC continues to evaluate options that might result in the required SCT benefit-to-cost ratio of 1.0 or greater. A particular challenge has been distribution-level constraints that don't require large capacity NWA solutions (i.e., sub-MW peak load reductions). One of the drivers of low SCT scores for the smaller NWA projects proposed to date has been the relatively large fixed costs to install and interconnect typical NWA solutions (e.g., large-scale battery energy storage, distributed generation).

~~T~~While there have been several R&SC customer DR program evaluations and improvements since the Company's DemandLink Pilot, including the Company's ongoing study with Fraunhofer USA to evaluate how potential DR participants interact with the Company's DR website interface~~. However~~, there have been very few studies completed that have attempted to address the underlying motivations that would lead a person to participate in a R&SC customer DR program. Rather, there has generally been an assumption that savings/incentives are the primary motivation; but behavioral research has shown that factors such as social recognition, injunctive and descriptive norms, environmental values, and competency motivations can be just as effective, but at a much lower program cost which ultimately results in lower costs to customers. The proposed Project will attempt to find out more about what makes potential participants engage in R&SC customer-facing programs and DR in particular, so the Company can better design the most cost-effective interventions.

Project Proposal

The Company proposes to work with Behavioral Economists and Scientists from University of Rhode Island's (URI)~~'s~~ College of Environment and Life Sciences and Energy Fellows Program to develop and test novel customer engagement approaches that are designed to increase enrollment, participation, and retention in R&SC customer programs that can be used for DR. Based on these novel customer engagement approaches, the Company will develop a new customer DR program to specifically address distribution-level peak loads in Rhode Island~~ (RI)~~ to help address critical distribution-level constraints. The new program will be ~~tested~~ demonstrated in a selected RI pilot area, to determine if the program can be used as an effective DR tool by the Company.

Phase 1 will leverage lessons learned from existing R&SC customer programs, including the Company's Tiverton DemandLink Pilot, evaluate residential energy storage and other new programs that could potentially be more effective and reliable for reducing peak loads~~and other existing R&SC customer programs~~, and use RI-specific demographics to develop a R&SC Customer DR Program Enhancement Plan for the State. The Company's current R&SC customer DR program, ConnectedSolutions, which is the successor program to DemandLink, has already undergone ~~a number of~~several significant program improvements, including marketing and user experience improvements based on usability testing conducted by Fraunhofer USA, and a "Bring Your Own Battery" option where DR participants can connect their EV charger or stationary energy storage system to the ConnectedSolutions platform. The Company also has significant experience with traditional EE programs, like LED replacement programs, which have been shown to be effective at reducing peak demand. The Company will consider optimization of these and other control-based and information-based DR enabling technologies for evaluation in the proposed pilot.

In addition to leveraging the Company's R&SC customer DR and EE experiences, Behavioral Economists and Scientists from URI will perform a thorough literature review and use the lessons learned from other customer DR programs, direct assessments, and RI customer demographics, to develop novel customer engagement approaches based on behavioral economic and other behavioral science principles that are designed to increase customer enrollment, participation, and retention for residential and small commercial customer classes. Qualitative (e.g., focus groups, interviews) or quantitative (e.g., surveys, experiments) direct assessments will be used to learn more about the obstacles, values and other motivations that are driving customer behavior around use of electricity. Novel approaches could include economic and non-economic motivations for behavior, based on accepted models of human behavior and social marketing. This may include approaches such as behavioral nudges, social recognition and peer leadership, and programs to increase perceived efficacy and behavioral control. More specifically, the proposed ~~pilot~~Study could explore a combination of dynamic tariff structure with different levels of information and/or nudges as an effective way to increase participation and couple it with the implementation of a loyalty program (rewards for longevity or efficiency) to retain customers. The novel approaches will be incorporated into a comprehensive R&SC Customer DR Program Enhancement Plan for the State~~, which will be reviewed with the RI SRP Collaborative~~.

Phase 2 will engage the Company's subject matter experts ~~and the RI SRP Collaborative~~ to select a favorable pilot location to test the novel approaches developed in Phase 1. Selection will be based on the potential for R&SC customer DR to address a specific distribution-level need and will include factors such as customer classes, housing stock, utility access, income levels, and other demographics specific to areas in Rhode Island with particular electrical distribution-level constraints as indicated by the heat maps presented on the Company's System Data Portal.[18]

Next, the Company will develop a RI Pilot R&SC Customer DR Program Implementation Plan to specifically address distribution-level peak loads in the selected area based on the novel customer engagement approaches developed in Phase 1. The Implementation Plan will consider a variety of control-based and information-based DR enabling technologies including internet connected, remote control & monitoring, smart/self-learning, and automation devices and appliances (e.g., ~~smart thermostats~~connected devices, energy storage, home energy monitors, targeted LED lighting, EV chargers, automated window covering control). The Plan will also consider the possible synergistic effects of bundling the DR program with other programs offered by the Company, including the Community Initiative, Home Energy Reports, and ~~and~~ Energy Efficiency Retrofit Programs (e.g., ~~EnergyWISE~~EnergyWise single family retrofit program).

The Company shall share an initial version of the RI Pilot R&SC Customer DR Program Implementation Plan by December 31, 2019.

Finally, the Company will work with subject matter experts and the Collaborative to develop performance metrics to gauge the success of the demonstration testing to be conducted in Phase 3. Metrics may include the cost effectiveness of enrollment, participation, retention, scalability, and capability to reduce peak demand to help address specific electrical distribution-level constraints.

[18] Note that it is not the intent of the project to demonstrate that customer-facing programs, and customer DR in particular, can solve all distribution-level problems, but rather that they can be effective tools to help reduce peak demand, particularly as the Company develops better communication with its customers and more and more customers' appliances, and loads in general, become connected.

Phase 3 will evaluate and test the novel customer engagement approaches incorporated into the Implementation Plan using the pilot location selected in Phase 2. The Company will work with URI, existing DR and EE program administrators, and procure additional third-parties as needed, to deploy the DR technology, marketing, and retention measures outlined in the Implementation Plan. The Company will also work with URI and selected third parties to develop an evaluation plan, perform measurement and verification (M&V) and evaluation of pilot results, and make future recommendations based on the performance metrics established in Phase 2 and lessons learned from the pilot deployments.

Schedule

If approved by the PUC, the proposed Project would commence on January 1, 2019. Phase 1 would require 8 months and Phase 2 would require 4 months. It is anticipated that Phase 3 would require ~~between two and~~ three years, ~~depending on the~~but the duration and timeline will be finalized at the end of Phase 2 ~~scope of Phase 3 and results from initial deployments~~.

Program Funding Plan

The Company estimates that it will require $175,000 to implement phases 1 and 2 of the Project in 2019. Of this amount, $100,000 is associated with funding for URI to conduct the study and complete the Customer DR Program Enhancement Plan in Phase 1 and $75,000 is estimated for program planning and management including completion of the RI Pilot R&SC Customer DR Program Implementation Plan in Phase 2.

Specific funding requests for the additional years of Phase 3 of this Study will be proposed in subsequent SRP Reports.

Evaluation

The Company is proposing to work with a third-party ~~evaluator~~vendor for the evaluation ~~tasks~~ in Phase 3. A specific evaluation plan will be determined at the start of Phase 3, but evaluation criteria may include peak demand reduction load, duration and frequency capabilities;~~,~~ and DR program enrollment, participation, retention, and overall cost effectiveness. The first year of the project will be evaluated using updated BCA calculations based on the results of phases 1 and 2.

Benefit Cost Analysis

The BCA SCT score for the proposed project is estimated to be 2.15 assuming the DR pilot project costs and other assumptions summarized in the tables below. Because the proposed DR pilot project costs are addressing the upfront investment needed to create a better R&SC Customer-Facing DR Program that can be used to reliably address distribution-level constraints, the BCA calculation was performed for the initial pilot

Formatted: Justified, Space After: 0 pt, Add space between paragraphs of the same style, Line spacing: single, No bullets or numbering project period (2019-2022) plus an additional 10-year period (2023-2032) over which time it is assumed the enhanced DR program will be deployed in other locations to address additional distribution-level constraints. Although it is not known in advance what kinds of distribution-level constraints will be discovered in future distribution area studies, it is assumed they will be of similar scale and cost for the traditional solution (i.e., "Wires Option") as the three NWA opportunity areas identified in the South County East (SCE) Area Study Distribution Planning exercise, which resulted in a total NWA peak load relief need of 5.1 MW. The deferral period is assumed to be 10 years.

The BCA calculation assumes 700 kW of peak load relief is addressed through the enhanced DR program resulting in a deferral of traditional distribution project costs at the end of the Initial DR Study Pilot (2022). For the next 10 years, it is assumed the enhanced DR Program can address 1.71 MW of new peak load relief each year with a similar traditional project costs deferral each year. On-going DR Program Costs assume $267 per kW of peak load relief incentive (plus inflation) for the connected device.[19]

The Study is primarily research, development and demonstration during Phases 1 through 3. In the ten years following Phase 3 (2023 through 2032), the Company plans to integrate learnings from the Study in future programs and projects that engage customers in Rhode Island.

Table 5: Customer-Facing Program Enhancement Study Benefit-Cost Summary

Customer-Facing Program Enhancement Study	
Total Cost	$3,447,059
Initial DR Study Pilot Costs (2019-2022)	$930,927
On-Going DR Program Costs (2023-2032)	$2,516,131
Total Benefits	$7,397,617
Net Benefits	$4,881,486
BC Ratio	**2.15**

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[19] Existing incentives for the connected devices and any bill credits associated with existing EE and DR programs would come out of the Company's respective budgets and would be accounted for in the BCA scores of those respective programs.

Rhode Island Locational Incentives

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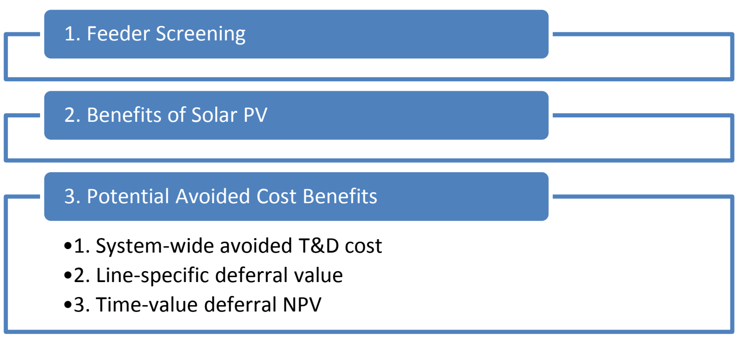
Summary of ~~National Grid's~~ the Company's Locational Incentive Analysis in Rhode Island in 2017

The Company's locational incentive research and analysis conducted in 2017 followed a three-phase approach: 1) expedited method for screening feeders; 2) understanding the benefits solar could provide; and 3) determination of potential avoided cost benefits. This third step encompassed three different approaches to estimate potential benefits from load relief, both broadly and at specific locations: 1) system-wide avoided transmission and distribution cost; 2) ~~line~~feeder-specific deferral value of distribution system upgrades as measured by the avoided revenue requirement NPV, multiplied by the probability of a spot load developing necessitating an upgrade; 3) time-value deferral NPV, similar to what has been used for the SRP area.



The first step in the process was to conduct an analysis of feeders and substations in Rhode Island based on loading, asset condition, and expected growth ~~was determined~~ to provide a reasonable basis on which to consider Locational Incentives within the RE Growth Program. The following screening criteria were used in the Rhode Island analysis: feeders loaded at least 80% in the last year; the asset must not be scheduled for upgrade due to asset age or condition; load on the asset must be growing, based on load forecasting results. ~~This criteria~~These criteria ~~is~~are similar to the criteria used in the New York Marginal Avoided Distribution Capacity (MADC), which is explained further in the next section. The result of this analysis in Rhode Island was a list of 25 feeders that passed the screening criteria.

Each of the 25 feeders was then further analyzed for peak hour times. The top three percent of hours by kVA on each feeder were sorted by hour for historical 2015 and 2016 years. The resulting analysis shows that two groups of feeders peak at different times, with a group that peaks early, and a second group that peaks late. The time of peak significantly impacts the potential value that solar can provide to reduce loading, and thus the amount of incentive it might earn.

While some of these feeders are heavily loaded, zero are scheduled to be upgraded in the next three years and none are predicted to reach 100% loaded by 2027, except for those in the SRP pilot. In other words, none of the feeders were forecasted to be constrained within our ~~three year~~three-year planning horizon and criteria, and there is no cost to defer. Whether a constraint suddenly appears, and its location, is uncertain. Roughly one percent of feeders require upgrades annually due to spot/pop-up loads.

Because there were no constraints and no costs to avoid, the Company deferred further development of a Locational Incentive program. The Company did outline how it could design and calculate a potential locational incentive if forecasts point to constraints in the future. That process is~~t~~ outlined below and it is still the process the Company proposes to use if forecasts point to constraints in the future.

During the next phase of the process, the Company used historical solar data to understand the benefits that solar photovoltaics (PV) could provide to the distribution system. Solar PV output is the result of system losses and solar insolation, driven by latitude, cloud and snow cover, shading and orientation and degree of tilt. ~~Capacity factor is a measure of the percentage of time, on average, that a system can operate at its peak nameplate rating. Available capacity differs by minute and hour, which can serve load locally and reduce peak demand on the equipment.~~ National Grid partnered with Peregrine Energy to study solar contribution to distribution load relief in 2014 in the SRP Pilot area. The study coined the term Distribution Contribution Percentage, meaning the capacity factor for solar systems over the peak period. The Company analyzed solar output by hour and categorized the summer months (June through September) into two time periods that represented where the feeder peak hours aligned, Group A (1pm-4:59pm) and Group B (4-7:59pm). The solar output data was sourced from the National Renewable Energy Laboratory's (NREL's) PVWatts® Calculator. These four hours of peaking were multiplied by the four summer months, with an average of 30 days each, to reach a total Summer Capacity Factor of 480 peak hours. Using the same math, the Monthly Capacity Factor is 120. Both the total Summer Capacity Factor and individual summer months Capacity Factor were calculated for each azimuth using the following calculation:

Summer Capacity Factor = Sum of kWh solar output in Group / (number hours in Group * days in month) / 1000

The four summer months were then totaled to reach a total Summer Capacity Factor by azimuth.

Below is an example of the calculation performed for last year, using the following data:

Table 6: Summer Capacity Factor Data for Calculation

Average kWh by Hour, Summer Only – 180° azimuth	Sum of kWh solar Output, Group A	Capacity Factor, Group A	Sum of kWh solar Output, Group B	Capacity Factor, Group B
June	44,691	37.24%	9,382	7.82%
July	48,534	40.45%	10,600	8.83%
August	45,948	38.29%	7,873	6.56%
September	33,983	28.32%	3,900	3.25%
Summer Capacity	173,157	36.07%	31,754	6.62%

Group A Summer Capacity Factor June = 44,691/ (4*30)/ 1000 = 0.3724

The Company examined lost revenue by azimuth and system size and found that south facing systems produce more total energy. However, west facing systems produce more energy late in the afternoon, which is more closely aligned with peak system, which is when it can provide added value.

Method 2 Adders do not make up lost base revenue for small systems; Method 1 and 2 incentives are almost large enough to justify 210 orientations for large systems; Relative Compensation is closer to breakeven for Method 2.

Lastly, the Company utilized three different approaches to estimate potential benefits from load relief, both broadly and at specific locations.

First, the Company calculated a system-wide Avoided Transmission and Distribution (T&D) cost. This cost approach is a system wide approach that looks at historic and forecast summer peak impacts for T&D. The marginal cost of transmission and distribution capacity in the Energy Efficiency T&D cost estimate is $93.16/kW-year. This assumes that all growth dollars are truly capacity related versus service connection related. When expected Energy Efficiency and DG program impacts are included in the forecast, these forecast growth spend dollars are naturally spread over much fewer MWs of growth due to minimal load growth, resulting in $/kW-year values that do not make sense. Therefore, this approach does not provide a useful measurement of the locational specific cost of growth to be considered with analyzing the post-Energy Efficiency and post-DG program forecast due to the granular nature of new service spending.

Second, the Company calculated a line-specific deferral value of distribution system upgrades as measured by the avoided revenue requirement net present value (NPV), multiplied by the probability of a spot load developing and necessitating an upgrade. The first step was to determine the "feeder cost"~~s~~. Since the location of future constraints is uncertain, the Company developed a feeder-specific weighted average cost per mile:

$\text{Feeder Cost}_i = (C_0 * M_{0i} + C_U * M_{Ui}) / (M_{0i} + M_{Ui})$

Where:
C_0 is system average cost of installing overhead feeder per mile
M_{0i} is miles of overhead per feeder
C_U is system average cost of installing underground feeder per mile
M_{Ui} is miles of underground per feeder

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The Company then employed two methods to determine this line-specific deferral value, named Method 1 and Method 2. To relieve constraints in some circumstances, two or three mile segments of feeder must be replaced, but a~~. A~~ base case of one mile upgrades was presented.

Method 1 is the probability-weighted avoided revenue requirement NPV. Over a ~~ten year~~ten-year deferral period, this would provide a probability weighting of approximately 10% of the avoided revenue requirement NPV. Method 2 is a ~~ten year~~ten-year deferral of the full revenue requirement. The Company calculated the difference in NPV between building an upgrade now, or with a ~~ten year~~ten-year delay.

Third, the Company calculated a time-value deferral NPV, similar to what has been used for the SRP plan area.

The Company then proposed potential approaches to a locational incentive structure. One approach is to distribute the annual deferral value over the total annual avoided peak demand (i.e., kWs that are generated or reduced by the distributed energy resources - DERs)~~value of additional capacity~~. Lump sum payments or annualized payments are possible. Lump sum payments more closely mimic installation costs and would be applied to smaller projects less than 25 kWh without interval meters. This would be a per kW of peak production payment and actual incentives would be scaled by predicted system production ~~over~~during the predicted peak periods.

~~-~~Annualized ~~based~~ payments ($/kWh value) based on the actual DER output during the actual ~~in~~ peak periods better ~~incentivizes~~incentivize actual performance.

Current Status of Distributed Generation Growth in Rhode Island

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Rhode Island has a long, successful history at incentivizing developers to install DG in the state through the use of existing feed in tariffs. As presented at the Rhode Island Quarterly DG Interconnection Meeting in July 2018, interconnection trends for both DG applications received (number of applications and megawatts) and for DG interconnected (number of applications and megawatts) have trended upwards since 2011. This trend is applicable to both complex and simple projects.

Table 7: Rhode Island Complex Interconnection Application Trends

	Received Applications- Complex		Interconnected Applications- Complex	
	MW	Apps	MW	Apps
2011	25.0	27	1.0	8
2012	36.0	60	7.2	12
2013	23.0	53	13.3	19
2014	23.2	47	17.8	22
2015	58.9	102	3.3	27
2016	134.2	139	21.1	52
2017	297.3	149	23.8	55
2018	349.9	161	5.5	27
Total	947.6	738	93.0	222

~~Table 1: Rhode Island Complex Interconnection Application Trends~~

Table 8: Rhode Island Simplified Interconnection Application Trends

	Received Applications- Simple		Interconnected Applications- Simple	
	MW	Apps	MW	Apps
2011	0.2	30	0.2	21
2012	0.2	41	0.3	45
2013	0.3	77	0.2	51
2014	0.6	127	0.4	77
2015	3.2	599	1.9	329
2016	10.1	1,724	8.1	1,351
2017	12.6	2,237	10.8	1,832
2018	7.7	1,313	4.4	774
Total	34.8	6,148	26.4	4,480

~~Table 2: Rhode Island Simplified Interconnection Application Trends~~

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Current Status of Electric Peak Load in Rhode Island

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While the Locational Incentive analysis was performed in the summer of 2017, the current Rhode Island 2018 Electric Peak (MW) Forecast for the long-term (2018-2032)[20] continues to support the conclusion that the Rhode Island service territory is not experiencing load growth. The service territory is experiencing negative growth of -0.1% annually over the next fifteen years.

> "Forecasting peak electric load is important to the Company's capital planning process because it enables the Company to assess the reliability of its electrical infrastructure, enables timely procurement and installation of required facilities, and it provides system planning with information to prioritize and focus their efforts. In addition to these internal reliability and capital planning internal uses, the peak forecast is also used to support regulatory requirements with the state, federal, and other agencies.

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> Narragansett Electric Company's (NECO) peak demand in Rhode Island in 2017 was 1,68~~8~~2[21] , on Thursday, July 20th at hour-ending 16. The 2017 peak was 15% below the NECO all-time high of 1,985 MW reached on Wednesday, August 2, 2006.

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> This ~~summer's~~summer's [2017] peak weather was considered cooler than normal (average). This year's peak is estimated to be 35 MW below the peak the company would have experienced under normal weather conditions. Thus, on a weather adjusted "normal" basis, this year's peak was estimated to be 1,723 MW, a decrease of -3.1% vs. last year's weather-adjusted 'normal' peak.

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> The forecast indicates that the overall service territory will experience negative growth of -0.1% annually over the next fifteen years, primarily due to the impacts of energy efficiency and solar PV offsetting any underlying economic growth." (p 4-5)

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The Company presented at the Rhode Island Quarterly DG Interconnection Meeting in July 2018 that by the end of 2018, the Company forecasts that Rhode Island's electric load will be reduced by 1.2% from historical load levels. This reduction is based ~~only off~~on an assumption of solar DG having~~with~~ a 21% annual average capacity factor and forecasted 25 MW of solar. By the end of 2019, the Company forecasts that Rhode Island's electric load will be reduced an incremental 0.4%~~. This reduction is based only~~

[20] National Grid Heat Map website http://ngrid-ftp.s3.amazonaws.com/RISysDataPortal/Docs/RI_Forecast_PEAK_2018_Report_rev1_Jan2018.pdf
[21] Meter Data Service's system level PRELIMINARY peak and subject to change

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~~off solar with a~~ , assuming 21% annual average capacity factor and forecasted 32 MW of solar.

In comparison, load growth in National Grid's New York service territory is estimated to be~~-~~ 0.1%.

New York Locational Value of Distributed Energy Resources

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Background

As part of its Reforming the Energy Vision (REV) initiative, the New York State Public Service Commission (PSC) in 2015 established a proceeding to replace net energy metering (NEM) with mechanisms to compensate Distributed Energy Resources (DER) that more accurately reflect the value they provide to the electric system. The VDER Phase One Order[22], issued March 9, 2017, adopted the Value Stack tariff as a mechanism to compensate~~r~~ newly interconnecting large DER projects, including Community Distributed Generation (CDG) and remote net metered (RNM) projects, as well as on-site projects located behind the meter of large C&I customers, for net energy injections onto the system. National Grid's Phase One Value Stack tariff became effective November 1, 2017. VDER Phase Two, which began in the summer of 2017, is on-going and, among other objectives, seeks to refine the Value Stack compensation components to more precisely reflect system values.

The Phase One Value Stack tariff includes two components to compensate qualifying DER for distribution system benefits provided: the Location System Relief Value (LSRV) and the Demand Reduction Value (DRV). Both the LSRV and DRV include a performance component where resources are paid for their contribution during the system's top 10 load hours. LSRV is a locational marginal cost for constraints on the system that could be relieved with DER. The DRV component represents the value that exists for T&D by virtue of DER being on the system. In the absence of locational marginal avoided distribution costs, the Commission directed each utility in the VDER Phase One Order to administratively "deaverage" the system average marginal costs calculated in its most recently filed Marginal Cost of Service study to arrive at initial LSRV and DRV values. Further, the Commission required each utility to file, by April 24, 2017, a work plan and timeline.~~—~~..[23] The Company's work plan filed in compliance with this requirement provided an outline for an Enhanced Marginal Cost of Service study to identify areas on its system where injecting DER may avoid distribution costs the MW demand reduction needed to avoid them, and to develop associated locational

[22] Case 15-E-0751 *et al.*, *In the Matter of the Value of Distributed Energy Resources et al.*, Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017) ("VDER Phase One Order").

[23] *Ibid.*, p. 155 (*see* ordering clause No. 13).

marginal avoided distribution costs, and to file the results at the time of filing the Company's 2018 Distributed System Implementation Plan (DSIP).

The Company filed its enhanced Marginal Cost of Service -study, hereafter known as the Marginal Avoided Distribution Capacity (MADC) study, on July 31, 2018. The MADC values resulting from the study reflect the marginal cost of forecast utility investments that may be avoided by DER that inject energy into the system or reduce load. The MADC operates at the granularity of the specific project (i.e. upgrading a transformer bank) which could be deferred by DER. MADC study outputs include locations where DER can defer the traditional project, which are generally at the feeder level~~,~~ but, in select cases, include higher-voltage lines. MADC outputs can be used as the basis for the LSRV and DRV components of the VDER Value Stack tariff and other purposes, such as compensation rates for demand response and targeted energy efficiency programs. Development of the MADC study required a team of ten engineers, with input from multiple functional units within the Company, to implement new processes and expanded capabilities across a range of software packages including PSS®E, ASPEN, TARA, Python, and Excel. New York Department of Public Service (DPS) Staff has stated the MADC study will be subject to approval by the Commission~~,~~ but, at this time, a regulatory process or timeline for such approval has not been established.

The MADC study was developed to determine locational values through a forward-looking system-wide assessment to determine (1) where DER may be able to provide locational support to the electric distribution system through targeted relief in areas where load growth will create electrical stress on the system, and (2) assigns a value to that relief by comparing it to the traditional investment needed to alleviate such problems. The MADC values provide estimates of the value of marginal increment of load relief on a $/kW basis based on the potential to defer the proposed traditional investment over the 10-year study horizon for each location. For the purpose of implementing the LSRV component of the Value Stack, the Company has bundled locational values into six pricing groups combining projects with a similar dollar per MW value to ease implementation and send a more consistent signal to the market.

MADC Study

As articulated in Section III of the Company's Work Plan and Timeline, the MADC study consists of four basic steps as follows:

A. Development of system-wide load flow model
B. Development of load and DER forecasts at the substation level
C. Identification of potential DER opportunities to address system needs

D. Evaluation of locational values

A. System-wide Load Flow Model

In order to develop an accurate assessment of locational distribution system marginal costs, National Grid developed an improved load flow model built upon the models submitted, along with the other New York Transmission Owners, through the NYISO in the aggregated 2017 FERC 715 Filing- which capture 2018 and 2027 summer peak 90/10 extreme loading cases consistent with a one-in-ten--year weather event. However, as those transmission-level load flow models are not sufficiently detailed for the purpose of the MADC study, the Company expanded the topology of the transmission load flow cases to include additional detail at lower transmission levels, the sub-transmission system, and the distribution system, including all distribution substation transformers and the corresponding low-side bus at each of these substations. This increased granularity resulted in a more integrated assessment of system impacts than previous planning approaches.

B. Load and DER Forecasting at the Substation Level

As proposed in the Work Plan and Timeline, the Company developed multiple sets of load and DER forecasts for each distribution substation. The MADC study evaluates two sets of forward-looking ten-year forecasts: a top-down forecast based on data available from the New York Independent System Operator ("NYISO") zonal level load data and growth trends, and a bottom-up Company forecast utilizing customer-level information to develop feeder-specific, 8,760 hour load profiles over the study horizon. The top-down zonal forecasts are disaggregated down to individual substations and the bottom-up feeder-level forecasts are aggregated or "rolled up" to create similar substation views. The bottom-up forecasts include the load of existing customers and scaling factors to account for projected loads from new customers.

While developed through different processes, National Grid applied both forecasts consistently as inputs to the load flow model. Both forecasts were built from a 2017 base year and then calibrated for a 95/5 weather event, —consistent with the Company's traditional distribution planning practices. The Company processed load flow assessments for both forecasts considering two DER scenarios: (1) without additional rooftop photovoltaic ~~("PV")~~ systems beyond those presently installed and (2) incorporating forecasted rooftop solar PV additions.

The following forecasts were evaluated in load flow cases:

1. 2018 summer 95/5 peak
2. 2027 summer 95/5 peak bottom-up load forecasts including new rooftop solar PV
3. 2027 summer 95/5 peak bottom-up load forecasts excluding new rooftop solar PV
4. 2027 summer 95/5 peak top-down load forecasts including new rooftop solar PV
5. 2027 summer 95/5 peak top-down load forecasts excluding new rooftop solar PV

C. Identification of DER Opportunities

Multiple load flow cases were analyzed to assess the system performance during coincident peak loading as well as during more localized non-coincident peak loading to capture the strain on local infrastructure. System needs considered thermal constraints, voltage excursions, and contingency at-risk load. For the duration of the ten-year study horizon, the model identified the specific constrained assets, the timing at which the planning criteria violations are forecasted to materialize and the kW magnitude of relief required to address the violation.

~~National Grid's~~The Company's engineering teams then developed traditional utility solutions for each of the violations identified from the load flow analyses. The cost estimates for each of the traditional solutions were based on recent projects and cost projections embedded in the Company's 2018 Three-Year Rate Case Order. The Company evaluated results from the load flow analyses against planning criteria to identify potential projects where the addition of DER could provide alternatives to traditional investment. Generally, if a need could be addressed by the capacity of DER, it was identified for further consideration with two exceptions. Projects were removed from the MADC study if an asset was already scheduled to be replaced due to age or state of repair (i.e., "asset condition,") and only if the updated infrastructure solved the constraint identified by the load flow model. Similarly, an existing project was removed from the MADC study if it appeared in National Grid's Capital Improvement Plan ("CIP") with an in-service date of 2020 or earlier. These imminent-need projects were excluded because the Company needs to replace those assets to meet planning standards for safe and reliable service regardless of the quantity of DER on the system.

For each defined violation, the Company created a list of locations where DER performance, aligned with system need, would be beneficial. In most cases, the locations include a list of feeders. In select cases, they also include higher voltage lines.
In cases where the locations for DER had the possibility to solve more than one model violation, and obviate the need for multiple potential projects, the Company adjusted the projected value of those locations appropriately given the type of project and size of the need.

D. Enhanced MCOS Study

As in the traditional MCOS study, crux of the MADC study is representing utility spending in a $/kW fashion. The Company used the study results – the size of the need, the timing, and the cost of the traditional solution – to generate a schedule of revenue requirements that could be deferred by DER. This is conceptually similar to the procedure the Company used in assessing its Village of Kenmore non-wires alternative ("NWA") project and plans to use going forward to evaluate other NWA opportunities.

The MADC study results are unique estimates of the value of a marginal increment of load relief on a $/kW basis based on the potential to defer the proposed traditional investment over the ten-year study horizon for each location. This $/kW estimate can become the basis for locational compensation in expanded DR programs or the LSRV in the VDER Value Stack tariff.

The results of the study were used to generate locational MADC values, a schedule of revenue requirements of the 68 unique areas of the Company's system where an appropriate quantity of DER could effectively defer the need for traditional utility investment over the 10-year duration of the study. In New York, National Grid's traditional Marginal Cost of Service (MCOS) study is primarily used for specific ratemaking purposes and (1) does not calculate marginal costs on a locational basis, and (2) is based on a historical sample of utility infrastructure projects that cannot be avoided by demand reductions from DER. In comparison, the expressed purpose of the MADC is to inform compensation for locational distribution system costs that may be avoided by DER.

The MADC study was developed to determine locational values through a forward-looking system-wide assessment to determine (1) where DER may be able to provide locational support to the electric distribution system through targeted relief in areas where load growth will create electrical stress on the system, and (2) assigns a value to that relief by comparing it to the traditional investment needed to alleviate such problems. The MADC values provide estimates of the value of marginal increment of load relief on a $/kW basis based on the potential to defer the proposed traditional investment over the 10-year study horizon for each location. This $/kW estimate can become the basis for locational compensation in expanded demand response programs, targeted Energy Efficiency programs, or the LSRV and DRV components of the VDER Value Stack tariff. For the purpose of implementing the LSRV component of the Value Stack, the Company has bundled locational values into six pricing groups combining projects with a similar dollar per MW value to ease implementation and send a more consistent signal to the market.

The MADC study is structured in the following manner: ignores sunk costs and only analyzes future projects over the scope of the 10-year study period; focuses only on capital costs which may be avoided or deferred by changes in load and demand; considers locational specific values at the substation or distribution feeder level, down to the granularity of the traditional project which could be deferred or avoided.

-Creating the New York MADC study required four steps:

1. Development of system-wide load flow model
2. Development of load and DER forecast at the substation level
3. Identification of potential DER opportunities to address system needs

4. Evaluation of locational values for MADC study

Development of a system-wide load flow model was necessary in order to develop an accurate assessment of marginal costs on locations on the distribution system. The existing transmission load flow models were not sufficiently detailed, so the Company expanded the topology of the transmission load flow cases to include additional detail at lower transmission levels, the sub-transmissions system, and the distribution system including all distribution substation transformers and the low-side bus at each of these substations.

The MADC was then applied to determine the LSRV value and the DRV value for the VDER Value Stack tariff.

Current Status of VDER Proceeding

On July 26, 2018, New York Staff filed the *Staff Whitepaper on Future Community Distributed Generation Compensation* (hereafter referred to as the Whitepaper) in response to Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources, and Case 15-E-0082, Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program.

Based on the Commission's guidance, the current status of the market, and analysis performed by Staff and NYSERDA, the Whitepaper outlines the following changes for National Grid:

(1) Remaining capacity within each territory should be reallocated and divided between two new Tranches, Tranche 5 and 6, with enhanced Market Transition Credit (MTC)[24] values (this applies for National Grid, as well as for Rochester Gas and Electric Corporation (RG&E) and New York State Electric & Gas Corporation (NYSEG));
(2) In addition, to further ensure that all New Yorkers are able to take advantage of the benefits of Community Distributed Generation (CDG), Staff will work with NYSERDA and stakeholders to investigate and propose options for allowing submetered customers to receive the MTC or similar compensation.

[24] The VDER Phase One Order established Phase One Net Energy Metering (NEM), which includes a limited continuation of NEM-style compensation, and an adder to the Value Stack for mass market customers, which is referred to as the Market Transition Credit (MTC).

In considering the various options available for CDG compensation beyond Tranche 4, Staff is guided by the Commission's direction to evaluate the viability of a statewide MTC and to develop recommendations for moving beyond Tranche 4 that would not unreasonably burden a particular group of ratepayers. Consideration of a statewide-funded MTC or similar mechanism also offers the opportunity to evaluate the status and viability of currently open Tranches in each utility service territory and ensure that reasonable and viable opportunities for distributed generation are available across the state, along with fairly allocating the costs associated with the MTC.

As these Tranches become filled and the incentives exhausted, Staff will continue to work with NYSERDA and stakeholders under the VDER transition to evaluate further market changes, including the implementation of cost reduction initiatives and improved Value Stack components, and determine what further intervention is appropriate.

New York Analysis as a Model for Rhode Island Analysis

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The Company's New York jurisdiction is involved in an ongoing, multi-year process of developing a mechanism to transition to a new way to compensate DER. It is important to understand how the policy, the adoption rates of DG, and the forecasting methods in New York differ from Rhode Island, and why for all those reasons, the Company does not propose to follow the NY VDER process.

In New York, LSRV is not an additional incentive in addition to net metering, it is a price signal that is designed to replace net metering. The expressed purpose of LSRV is to compensate DER in New York and with the latest developments in the New York process~~,~~, the regulators want to consider improvements that could spur development of community distributed generation (CDG) in areas where it has not flourished. As shown above, unlike New York, Rhode Island already has a long and successful history of incentivizing developers to install DG. Therefore, the need that exists to create this locational price signal to support DG in New York does not exist in Rhode Island.

Proposal for Locational Incentives in Rhode Island

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The Company proposes to further the work from last year's effort by using the deferral value for specific NWA locations to provide an incentive for bidders to respond to when the NWA RFPs are issued late in 2018 as per the 2018 plan. In order to provide value back to customers, the Company would use 80% of the deferral value and estimate the number of ~~kWhs~~kilowatt-hours needed in a location (load relief needed in kWs times the estimated hours the load relief is needed) and then calculate a per kWh~~H~~ credit to be paid based on performance of the winning bidder's project/program. The Company expects to file for approval to pay these incentives along with the proposals that the Company expects to fund with the incentives.

In addition, the Company recognizes the desire to more fully implement the entire NWA and location incentive conversation with the work proposed in a particular year's ISR filing. To assist in this effort, the Company will host quarterly NWA/locational incentive meetings to provide further transparency to the DPUC, OER, and the EERMC consultant team.

Under the Rhode Island Power Sector Transformation, the Company received a Decision on August 3, 2018 allowing it to pursue electric transportation in Rhode Island. Additionally, the Decision stated that the utility must include opportunities for Electric Vehicles in distribution level planning. While factors such as advances in energy efficiency, distributed solar, and behind-the-meter storage decrease utility load, the electrification of transportation and heat are expected to reverse that trend. One report that supports this trend is the U.S. Department of Energy's National Renewable Energy Laboratory (NREL) 2018 report, *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United* States[25]. This report is the second publication in a series and presents scenarios of electric end-use technology adoption and resulting electricity in the United States. The scenarios in the report reflect a wide range of electricity demand growth through 2050 that result from various electric technology adoption and efficiency projections in the transportation, residential and commercial buildings, and industrial sectors. Their analysis examined three scenarios and the results from all three scenarios predict steady demand growth across the next three decades, largely driven by the adoption of electric vehicles. The Reference scenario, which is largely consistent with the U.S. Energy Information Administration's Reference scenario that reflects laws, policies, and regulations as of 2017, has the most limited impacts from electrification, but still leads to a compound annual growth rate (from 2016 to 2050) in electricity demand of 0.65% and 4,722 terawatt-hours (TWh) of total consumption by 2050. In the Medium and High scenarios, total 2050 electricity demand is estimated to be 934 TWh (20%) and 1,782 TWh (38%) greater, respectively, than in the Reference scenario. In addition to growth in annual electricity consumption driven to a large degree by greater adoption of plug-in electric vehicles, electrification has the potential to significantly shift load shapes, particularly due to increased reliance on electric heat pumps for space and water heating needs.

Given Rhode Island's Zero Emission Vehicle (ZEV) Draft Plan goals for growing EV adoption more than 40-fold by 2025, the Power Sector Transformation Order on electric

[25] Mai, Trieu, Paige Jadun, Jeffrey Logan, Colin McMillan, Matteo Muratori, Daniel Steinberg, Laura Vimmerstedt, Ryan Jones, Benjamin Haley, and Brent Nelson. 2018. Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71500. https://www.nrel.gov/docs/fy18osti/71500.pdf.

transportation, the Energy Efficiency electric heat program under Docket Number 4755, and recent studies, the increase in DC Fast Charging will have to be managed with appropriate electrical service and distributed generation and storage resources to effectively prevent system overloading and to avoid utility peak demand charges. The Company does see an opportunity in the future to offer locational incentives in locations where load on the electric distribution system is increasing due to the growth of EVSE and electric heat.

Advancing Docket 4600 Goals

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Docket 4600 articulates several distinct goals for the electric system in Rhode Island:

i. Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels);

ii. Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures;

iii. Address the challenge of climate change and other forms of pollution;

iv. Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits;

v. Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society;

vi. Appropriately charge customers for the cost they impose on the grid;

vii. Appropriately compensate the distribution utility for the services it provides;

viii. Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives.

The Company's Locational Incentive proposal advances or is neutral to the Docket 4600 goals as seen in the table below.

~~*Table 3: Locational Incentive proposal expected to advance Docket 4600 goals*~~

Table 9: Locational Incentive proposal expected to advance Docket 4600 goals

GOALS FOR "NEW" ELECTRIC SYSTEM	Locational Incentives
Provide reliable, safe, clean, and affordable energy	Y
Strengthen the Rhode Island economy	Y
Address climate change and other forms of pollution	Y
Prioritize and facilitate increasing customer investment in their facilities	Y
Appropriately compensate distributed energy resources	Y
Appropriately charge customers for the cost they impose on the grid	Y
Appropriately compensate the distribution utility	Neutral
Align distribution utility, customer, and policy objectives and interests	Y

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SRP Incentive Mechanism Proposal

The Company and the Parties have agreed on a proposal comprised of a combination of action-based and savings-based metrics for the Company to earn incentives on work completed through SRP in 2019.

Action-Based SRP Incentives

The Company will earn an incentive equal to a portion of the 2019 SRP budget for completing certain actions, as described in this Report, by the milestone date stated in this Report. The actions and associated percentages of the 2019 SRP budget the Company can earn are:

Table 10: Summary of Action-Based SRP Incentives

Section	Action	% of 2019 SRP Budget
Consideration of NWAs in System Planning	Issue RFPs for NWA Resources	2%
Market Engagement with NWAs	Share Marketing & Engagement Plan	1%
Little Compton Battery Storage Project	Battery Installed and Operational	1%
South County East NWA Projects	Select Winning Bids	1%
Customer-Facing Program Enhancement Study	Share RI Pilot R&SC Customer DR Program Implementation Plan	1%

Accordingly, if the Company were to implement all the initiatives referenced above by the dates defined in this Report, it would earn a maximum of 6% of the 2019 SRP budget. The 2019 SRP budget would be defined as all the costs required to implement the SRP initiatives described above. This SRP budget would be determined in the SRP Report, prior to the commencement of 2019 SRP activities. The amount of SRP incentives earned would be based on this initial budget, not on the actual dollars spent to implement the initiatives.

Savings-Based SRP Incentives

The Company will also be able to earn savings-based incentives for those DERs that are installed as a result of the SRP initiatives described above. The Company will be obligated to demonstrate that DERs were installed as a result of the SRP initiatives. This demonstration would require: 1) an affidavit from the DER provider that Company marketing influenced their decision to site, and 2) confirmation that the DER was installed in the current year of the SRP plan (i.e. calendar year 2019). In future SRP plans (2020 and on), there will be a third requirement: measured output at the feeder during peak hours showing the specific DER's contribution to peak load reduction.

Commented [CM9]: Incentive section also existed in last year's SRP 2018 Plan and is mostly similar (despite redlining), though incentive actions modified for new current year SRP 2019 Plan

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For the Company to earn savings-based incentives on them, the DERs must be deemed cost-effective according to the Rhode Island cost-effectiveness framework established in the Commission's Docket 4600 Guidance Document. DERs that are statutory such as net metering and renewable energy growth (REG) are assumed to be cost effective as per the PUC's initial guidance in the Docket 4600 process.

Savings associated with programs for which the Company earns an incentive from other sources (e.g., REG) will not be included in the Company's savings-based incentive calculation.

The savings-based incentive will allow the Company to earn a share of the net benefits of the installed DERs that meet the demonstration criteria described above. Net benefits will be defined using the Utility Cost test, which includes only the "power sector" costs and benefits in the Rhode Island cost-effectiveness framework. Participant and societal costs and benefits will not be included for the purpose of determining the shared savings incentive amount. The Utility Cost test provides the clearest indication of the extent to which DERs reduce costs for all customers. Net benefits will include the location-based avoided distribution costs, if applicable, prepared by the Company, as described above.

In 2019, the net benefits of the DERs will be shared by allocating 20% to the Company and 80% to customers. The savings-based incentive mechanism would be applied to the net benefits of the Project proposed in this Report, as well as any projects installed and marketed as a result of the other SRP initiatives proposed in this report, to the extent they meet the criteria outlined in this section. The proposed incentive mechanism, assuming the Company meets the threshold requirements for earning the incentive, is illustrated below in the calculation of the savings-based incentive associated with the Project proposed in this Report.

Project Net Benefits[26]:	$566,816
Company Incentive Share:	20%
Company Incentive:	$113,363

The Company has not included a budget line item for incentives in this SRP Report. Any incentive earned by the Company will be calculated and included as part of the 2020 SRP Report funding request.

[26] From page 23 of this Report

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201~~8~~9 System Reliability Procurement Funding Request

The Company proposes to fund the projects and initiatives included in this SRP Report through the energy efficiency charge on customers' bills, as has been done in the past. The tables below illustrate the breakdown of the Company's funding request and the proposed customer charge associated with SRP for 2019.

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Table 11~~10~~: Summary of 2019 SRP Funding Request

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SRP Initiative	Cost
Marketing & Engagement Plan	$124,800
Little Compton Battery Storage	$109,500
Customer-Facing Program Enhancement Study	$175,000
South County East RFP Evaluation	$50,000
Total	**$459,300**

Table S-1: RI SRP 2019 Funding Sources

Table S-1
National Grid
System Reliability Procurement
Funding Sources
$(000)

		2019
(1)	**2019 SRP Budget**	**$459.3**
(2)	**Projected Year-End Fund Balance and Interest:**	**$574.2**
(3)	**Customer Funding Required:**	**-$114.9**
(4)	**Forecasted kWh Sales:**	**7,242,559,891**
(5)	**Additional SRP Funding Needed per kWh:**	**-$0.00002**
(6)	**Proposed Energy Efficiency Program charge in EEPP**	**$0.01149**
(7)	**Proposed Total Energy Efficiency Program charge in EEPP**	**$0.01147**
(8)	**Proposed Total Energy Efficiency Program charge w/ Uncollectible Recovery**	**$0.01161**

Notes
(1) Projected Budget includes only additional funds for SRP. It does not include costs associated with focused energy efficiency.
(2) Proposed Total Energy Efficiency Program charge is the sum of the "Additional SRP Funding Needed per kWh" and "Proposed Energy Efficiency Program charge in EEPP" lines.
(3) All dollar amounts shown are in $current year.

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Miscellaneous Provisions

A. Other than as expressly stated herein, this Settlement establishes no principles and shall not be deemed to foreclose any party from making any contention in any future proceeding or investigation before the PUC.

B. This Settlement is the product of settlement negotiations. The content of those negotiations is privileged and all offers of settlement shall be without prejudice to the position of any party.

C. Other than as expressly stated herein, the approval of this Settlement by the PUC shall not in any way constitute a determination as to the merits of any issue in any other PUC proceeding.

The Parties respectfully request the PUC approve this Stipulation and Settlement as a final resolution of all issues in this proceeding.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID

____

By its Attorney, Date
Raquel J. Webster

Appendices

Appendix 1
Rhode Island and Company Electric Service Projected Load Growth Rates

Appendix 2
Tiverton NWA Pilot Benefit Cost Analysis Tables

Appendix 3
Tiverton Pilot Evaluation Deliverables from Opinion Dynamics Corporation

Appendix 4
Projects Screened for NWA

Appendix 1 – Rhode Island Company Electric Service Projected Load Growth Rates

RHODE ISLAND PROJECTED GROWTH RATES (Percents)

State	County	Town	Annual Growth Rates (percents) 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	5-yr avg '18 to '22	10-yr avg '18 to '27
RI			-1.0	-0.9	-0.7	-0.4	-0.2	-0.1	0.1	0.3	0.4	0.4	-0.7	-0.2
	Bristol		-1.4	-1.3	-1.0	-0.8	-0.5	-0.4	-0.1	0.1	0.2	0.2	-1.0	-0.5
	Kent		-1.3	-1.2	-1.0	-0.7	-0.5	-0.3	-0.1	0.2	0.3	0.2	-0.9	-0.4
	Newport		-1.2	-1.2	-0.9	-0.6	-0.4	-0.3	0.0	0.2	0.3	0.2	-0.9	-0.4
	Providence		-1.1	-1.0	-0.8	-0.5	-0.3	-0.2	0.1	0.3	0.4	0.3	-0.7	-0.3
	Washington		0.1	0.0	0.2	0.3	0.5	0.5	0.7	0.9	0.9	0.8	0.2	0.5
	Newport	Little Compton	-0.5	-0.5	-0.3	-0.1	0.0	0.1	0.3	0.5	0.6	0.5	-0.3	0.1
	Newport	Tiverton	-0.1	-0.2	0.0	0.2	0.3	0.4	0.6	0.7	0.8	0.7	0.0	0.3

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Appendix 2 – Tiverton NWA Pilot Benefit Cost Analysis Tables

Table S-2
System Reliability Procurement - 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[1]	$90.2	$1,015.1	$716.7	$1,024.8	$435.0	$66.94	$0.0	$3,348.7
SRP Energy Efficiency Benefits[2]	$88.8	$310.4	$136.8	$78.0	$88.1	$341.6	$0.0	$1,043.7
Demand Reduction Benefits[3]	$0.0	$0.0	$5.6	$6.8	$5.3	$11.3	$0.0	$28.9
Deferral Benefits[4]	$0.0	$0.0	$174.2	$171.5	$159.4	$148.2	$0.0	$653.3
Costs	**$133.4**	**$672.4**	**$569.3**	**$1,029.4**	**$611.1**	**$510.9**	**$90.8**	**$3,617.4**
Focused Energy Efficiency Costs[5]	$46.6	$331.1	$195.8	$529.3	$280.1	$281.3	$0.0	$1,664.1
System Reliability Procurement Costs[6,7]	$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:

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

(2) SRP EE benefits include all TRC benefits associated with EE measures installed in each year that would not have been installed as part of the statewide EE programs.

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

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

(5) 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 programs. These are the programs through which measures in this SRP pilot will be offered.

(6) 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.

(7) All costs and benefits are in $current year except for deferral benefits.

(8) 2012-2017 numbers have been updated to reflect year end data. 2018 numbers reflect year end projections.

Table S-2
System Reliability Procurement - Tiverton/Little Compton
Summary of Cost Effectiveness ($000)

	2012	2013	2014	2015	2016	2017	Overall
Benefits	**$179.0**	**$1,325.4**	**$1,033.3**	**$1,281.1**	**$687.7**	**$668.5**	**$5,175.0**
Focused Energy Efficiency Benefits[1]	$90.2	$1,015.1	$716.7	$1,024.8	$435.0	$497.6	$3,779.4
SRP Energy Efficiency Benefits[2]	$88.8	$310.4	$136.8	$78.0	$88.1	$11.3	$713.3
Demand Reduction Benefits[3]	$0.0	$0.0	$5.6	$6.8	$5.3	$11.4	$29.0
Deferral Benefits[4]	$0.0	$0.0	$174.2	$171.5	$159.4	$148.2	$653.3
Costs	**$133.4**	**$672.4**	**$569.3**	**$1,029.4**	**$611.1**	**$1,122.6**	**$4,138.3**
Focused Energy Efficiency Costs[5]	$46.6	$331.1	$195.8	$529.3	$280.1	$804.0	$2,186.9
System Reliability Procurement Costs[6,7]	$86.8	$341.3	$373.5	$500.2	$331.0	$318.6	$1,951.5
Benefit/Cost Ratio	**1.34**	**1.97**	**1.81**	**1.24**	**1.13**	**0.60**	**1.25**

Notes:

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

(2) SRP EE benefits include all TRC benefits associated with EE measures installed in each year that would not have been installed as part of the statewide EE programs.

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

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

(5) 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 programs. These are the programs through which measures in this SRP pilot will be offered.

(6) 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.

(7) All costs and benefits are in $current year except for deferral benefits.

(8) 2012-2016 numbers have been updated to reflect year end data. 2017 numbers reflect year end projections.

Table S-3
National Grid
System Reliability Procurement - Tiverton/Little Compton
Annual Budgets and Actual Costs
$(000)

	Program Planning & Administration	Marketing	Rebates and Other Customer Incentives	Sales, Technical Assistance & Training	Evaluation & Market Research	Total
2012	$2.6	$24.7	$32.5	$2.0	$25.1	$86.8
2013	$67.9	$77.1	$102.0	$1.4	$90.7	$339.0
2014	$74.9	$78.1	$87.0	$6.0	$125.4	$371.5
2015	$90.6	$85.1	$67.6	$97.6	$157.2	$498.1
2016	$31.5	$89.6	$11.9	$60.0	$136.3	$329.3
2017	$9.5	$76.6	$3.5	$31.0	$109.0	$229.6
2018	$0.0	$0.0	$0.0	$0.0	$90.8	$90.8
Total	**$277.0**	**$431.3**	**$304.4**	**$198.1**	**$643.6**	**$1,854.3**

Notes:
(1) The annual totals in this table represent only the forecasted funds necessary to run the Tiverton/Little Compton pilot. They do not include costs associated with focused energy efficiency or with SRP participant costs.
(2) All amounts shown are in $current year.
(3) 2012-2017 numbers have been updated to reflect year end data. 2018 numbers have been updated to reflect year end projections

Table S-3
National Grid
System Reliability Procurement - Tiverton/Little Compton
Annual Budgets and Actual Costs
$(000)

	Program Planning & Administration	Marketing	Rebates and Other Customer Incentives	Sales, Technical Assistance & Training	Evaluation & Market Research	Total
2012	$2.6	$24.7	$32.5	$2.0	$25.1	$86.8
2013	$67.9	$77.1	$102.0	$1.4	$90.7	$339.0
2014	$74.9	$78.1	$87.0	$6.0	$125.4	$371.5
2015	$90.6	$85.1	$67.6	$97.6	$157.2	$498.1
2016	$31.5	$89.6	$11.9	$60.0	$136.3	$329.3
2017	$50.0	$80.0	$13.1	$54.4	$120.0	$317.5
Total	**$317.5**	**$434.6**	**$314.0**	**$221.4**	**$654.6**	**$1,942.1**

Notes:
(1) The annual totals in this table represent only the forecasted funds necessary to run the Tiverton/Little Compton pilot. They do not include costs associated with focused energy efficiency or with SRP participant costs.
(2) All amounts shown are in $current year.
~~(3) 2012-2016 numbers have been updated to reflect year end data. 2017 numbers have been updated to reflect year end projectsions~~

Table S-4
System Reliability Procurement - Tiverton/Little Compton
Summary of kW, and kWh New Installs Per Year

			Capacity (kW)			Energy (MWh)	
			Summer	Winter	Lifetime	Maximum Annual	Lifetime
2012	EE	Residential	17	20	102	121	642
		Commercial	4	2	44	7	85
		SRP	8	8	121	4	55
	Non-EE	Demand Response	13	0	13		
		Total	**42**	**30**	**280**	**132**	**782**
2013	EE	Residential	77	86	527	505	2,953
		Commercial	55	32	653	205	2,440
		SRP	78	33	1,362	80	883
	Non-EE	Demand Response	56	0	56		
		Total	**266**	**152**	**2,598**	**790**	**6,276**
2014	EE	Residential	50	59	419	334	2,737
		Commercial	12	9	128	69	758
		SRP	40	9	746	51	535
	Non-EE	Demand Response	17	0	17		
		Total	**120**	**78**	**1,310**	**455**	**4,030**
2015	EE	Residential	93	109	850	619	5,454
		Commercial	17	15	207	41	489
		SRP	23	7	396	26	271
	Non-EE	Demand Response	11	0	11		
		Total	**144**	**131**	**1,465**	**685**	**6,214**
2016	EE	Residential	50	58	464	318	2,807
		Commercial	5	4	61	29	359
		SRP	29	4	255	21	183
	Non-EE	Demand Response	6	0	6		
		Total	**90**	**67**	**786**	**368**	**3,349**
2017	EE	Residential	38	37	212	242	2,188
		Commercial	0	0	0	0	0
		SRP	22	38	257	200	1,796
	Non-EE	Demand Response	0	0	0		
		RFP	13	0	91	9	61
		Total	**74**	**75**	**560**	**450**	**4,045**
Grand Total			**735**	**532**	**7,000**	**2,880**	**24,696**

Notes:
(1) The "EE" savings include both Focused Energy Efficiency savings and SRP Energy Efficiency Savings.
(2) Measures unique to SRP and not offered in the same way through the statewide EE programs are listed as a separate line item (SRP) under the EE heading. Measures part of the focused EE are listed in the EnergyWise and Small Business program lines.
(3) Savings in this table are not cumulative. Each year shows savings from measures that will have been installed within that year.
(4) 2012-2017 numbers have been updated to reflect year end data.
(5) Demand Response estimated kWh savings are shown on table S-6.

Table S-4
System Reliability Procurement - Tiverton/Little Compton
Summary of kW, and kWh New Installs Per Year

			Capacity (kW)			Energy (MWh)	
			Summer	Winter	Lifetime	Maximum Annual	Lifetime
2012	EE	Residential	17	20	102	121	642
		Commercial	4	2	44	7	85
		SRP	8	8	121	4	55
	Non-EE	Demand Response	13	0	13		
		Total	**42**	**30**	**280**	**132**	**782**
2013	EE	Residential	77	86	527	505	2,953
		Commercial	55	32	653	205	2,440
		SRP	78	33	1,362	80	883
	Non-EE	Demand Response	56	0	56		
		Total	**266**	**152**	**2,598**	**790**	**6,276**
2014	EE	Residential	50	59	419	334	2,737
		Commercial	12	9	128	69	758
		SRP	40	9	746	51	535
	Non-EE	Demand Response	17	0	17		
		Total	**120**	**78**	**1,310**	**455**	**4,030**
2015	EE	Residential	93	109	850	619	5,454
		Commercial	17	15	207	41	489
		SRP	23	7	396	26	271
	Non-EE	Demand Response	11	0	11		
		Total	**144**	**131**	**1,465**	**685**	**6,214**
2016	EE	Residential	50	58	464	318	2,807
		Commercial	5	4	61	29	359
		SRP	26	4	255	21	183
	Non-EE	Demand Response	6	0	6		
		Total	**87**	**67**	**786**	**368**	**3,349**
2017	EE	Residential	41	49	625	336	4,795
		Commercial	8	8	104	32	394
		SRP	7	8	164	4	34
	Non-EE	Demand Response	1	0	1		
		RFP	0	0	0	0	0
		Total	**58**	**65**	**894**	**372**	**5,224**
Grand Total			**717**	**522**	**7,334**	**2,802**	**25,874**

Notes:
(1) The "EE" savings include both Focused Energy Efficiency savings and SRP Energy Efficiency Savings.
(2) Measures unique to SRP and not offered in the same way through the statewide EE programs are listed as a separate line item (SRP) under the EE heading. Measures part of the focused EE are listed in the EnergyWise and Small Business program lines.
(3) Savings in this table are not cumulative. Each year shows savings from measures that will have been installed within that year.
(4) 2012-2016 numbers have been updated to reflect year end data and 2017 numbers have been updated to reflect year end projections
~~(5) Demand Response estimated kWh savings are shown on table S-6.~~

Table S-5
System Reliability Procurement - Tiverton/Little Compton
Summary of Incremental Benefits By Year

			Capacity ($)						Energy ($)					Non-Electric ($)	
			Total Benefits	Summer Generation	Winter Generation	Transmission	MDC/ Deferral(3)	DRIPE	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	DRIPE	Resource	Non - Resource
2012	EE	Residential	68,954	2,735	0	2,314	9,724	473	17,057	8,696	10,374	4,444	5,586	0	7,552
		Commercial	21,251	1,709	0	984	4,135	474	2,831	688	1,698	338	627	0	7,765
		SRP	88,810	6,590	0	2,638	11,082	1,224	35	117	2,257	1,193	292	63,381	0
	Non-EE	Demand Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0
		Deferral	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	**179,015**	**11,035**	**0**	**5,936**	**24,941**	**2,171**	**19,924**	**9,500**	**14,329**	**5,975**	**6,505**	**63,381**	**15,317**
2013	EE	Residential	715,520	19,112	0	12,066	50,700	3,990	79,472	43,584	49,862	22,710	25,456	362,998	45,569
		Commercial	299,547	31,822	0	14,689	61,719	8,065	84,675	20,430	50,364	10,075	17,708	0	0
		SRP	310,370	67,287	0	30,582	128,499	14,693	261	967	45,399	16,336	6,346	0	0
	Non-EE	Demand Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0
		Deferral	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	**1,325,438**	**118,221**	**0**	**57,338**	**240,918**	**26,749**	**164,407**	**64,981**	**145,625**	**49,122**	**49,510**	**362,998**	**45,569**
2014	EE	Residential	641,519	29,866	0	17,044	0	3,214	68,295	46,885	41,650	17,727	35,790	350,408	30,639
		Commercial	75,220	11,229	0	5,201	0	963	26,032	6,580	12,466	2,916	9,835	0	0
		SRP	136,801	63,099	0	30,271	0	5,344	118	479	22,591	8,861	6,038	0	0
	Non-EE	Demand Reduction	5,563	1,989	0	3,521	0	0	0	0	54	0	0	0	0
		Deferral	174,188	0	0	0	174,188	0	0	0	0	0	0	0	0
		Total	**1,033,291**	**106,183**	**0**	**56,037**	**174,188**	**9,521**	**94,445**	**53,944**	**76,760**	**29,504**	**51,662**	**350,408**	**30,639**
2015	EE	Residential	953,990	74,891	0	34,529	0	7,247	153,698	83,936	75,394	38,919	72,456	366,076	46,844
		Commercial	70,792	21,238	0	8,337	0	1,422	18,325	4,693	9,039	2,126	5,611	0	0
		SRP	77,987	38,200	0	15,987	0	2,917	73	292	12,461	5,051	3,006	0	0
	Non-EE	Demand Reduction	6,802	2,411	0	4,074	0	0	0	0	317	0	0	0	0
		Deferral	171,482	0	0	0	171,482	0	0	0	0	0	0	0	0
		Total	**1,281,053**	**136,739**	**0**	**62,929**	**171,482**	**11,587**	**172,095**	**88,920**	**97,211**	**46,096**	**81,074**	**366,076**	**46,844**
2016	EE	Residential	399,334	65,614	0	5,410	0	0	82,277	50,023	37,105	20,112	1,543	115,983	21,267
		Commercial	35,633	9,151	0	702	0	0	14,076	3,648	6,434	1,454	168	0	0
		SRP	88,093	35,504	0	2,979	0	0	603	1,102	6,683	3,067	179	37,976	0
	Non-EE	Demand Reduction	5,260	3,604	0	1,224	0	0	0	0	431	0	0	0	0
		Deferral	159,412	0	0	0	159,412	0	0	0	0	0	0	0	0
		Total	**687,732**	**113,873**	**0**	**10,315**	**159,412**	**0**	**96,957**	**54,772**	**50,654**	**24,633**	**1,889**	**153,959**	**21,267**
2017	EE	Residential	386,311	45,043	0	3,371	0	0	66,000	36,872	31,049	16,835	664	161,410	25,067
		Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0
		SRP	358,713	40,403	0	3,035	0	0	57,016	29,961	28,040	13,190	591	161,410	25,067
	Non-EE	Demand Reduction	11,320	9,853	0	1,106	0	0	0	0	362	0	0	0	0
		Deferral	148,191	0	0	0	148,191	0	0	0	0	0	0	0	0
		Total	**904,536**	**95,299**	**0**	**7,512**	**148,191**	**0**	**123,016**	**66,833**	**59,451**	**30,026**	**1,255**	**322,820**	**50,133**
Grand Total			**5,411,064**	**581,351**	**0**	**200,066**	**919,132**	**50,028**	**670,844**	**338,950**	**444,030**	**185,356**	**191,895**	**1,619,643**	**209,769**

Notes:
(1) The "EE" benefits include both Focused Energy Efficiency benefits and SRP Energy Efficiency benefits.
(2) Measures unique to SRP are listed as a separate line item under the EE heading. Measures part of the focused EE are listed in the EnergyWise and Small Business program lines.
(3) The MDC/Deferral column represents: 2012-2013: the system-average distribution benefit and 2014-2017: the calculated deferral benefit as defined in the notes section of Table S-2
(4) All benefits are in $current year except deferral benefits which are in $2014.
(5) 2012-2017 numbers have been updated to reflect year end data.
(6) Benefits due to EE reflect new installations within the year. Benefits due to Non-EE reflect cumulative installations

Table S-5
System Reliability Procurement - Tiverton/Little Compton
Summary of Incremental Benefits By Year

			Capacity ($)						Energy ($)					Non-Electric ($)	
			Total Benefits	Summer Generation	Winter Generation	Transmission	MDC/ Deferral(3)	DRIPE	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	DRIPE	Resource	Non - Resource
2012	EE	Residential	68,954	2,735	0	2,314	9,724	473	17,057	8,696	10,374	4,444	5,586	0	7,552
		Commercial	21,251	1,709	0	984	4,135	474	2,831	688	1,698	338	627	0	7,765
		SRP	88,810	6,590	0	2,638	11,082	1,224	35	117	2,257	1,193	292	63,381	0
	Non-EE	Demand Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0
		Deferral	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	**179,015**	**11,035**	**0**	**5,936**	**24,941**	**2,171**	**19,924**	**9,500**	**14,329**	**5,975**	**6,505**	**63,381**	**15,317**
2013	EE	Residential	715,520	19,112	0	12,066	50,700	3,990	79,472	43,584	49,862	22,710	25,456	362,998	45,569
		Commercial	299,547	31,822	0	14,689	61,719	8,065	84,675	20,430	50,364	10,075	17,708	0	0
		SRP	310,370	67,287	0	30,582	128,499	14,693	261	967	45,399	16,336	6,346	0	0
	Non-EE	Demand Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0
		Deferral	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	**1,325,438**	**118,221**	**0**	**57,338**	**240,918**	**26,749**	**164,407**	**64,981**	**145,625**	**49,122**	**49,510**	**362,998**	**45,569**
2014	EE	Residential	641,519	29,866	0	17,044	0	3,214	68,295	46,885	41,650	17,727	35,790	350,408	30,639
		Commercial	75,220	11,229	0	5,201	0	963	26,032	6,580	12,466	2,916	9,835	0	0
		SRP	136,801	63,099	0	30,271	0	5,344	118	479	22,591	8,861	6,038	0	0
	Non-EE	Demand Reduction	5,563	1,989	0	3,521	0	0	0	0	54	0	0	0	0
		Deferral	174,188	0	0	0	174,188	0	0	0	0	0	0	0	0
		Total	**1,033,291**	**106,183**	**0**	**56,037**	**174,188**	**9,521**	**94,445**	**53,944**	**76,760**	**29,504**	**51,662**	**350,408**	**30,639**
2015	EE	Residential	953,990	74,891	0	34,529	0	7,247	153,698	83,936	75,394	38,919	72,456	366,076	46,844
		Commercial	70,792	21,238	0	8,337	0	1,422	18,325	4,693	9,039	2,126	5,611	0	0
		SRP	77,987	38,200	0	15,987	0	2,917	73	292	12,461	5,051	3,006	0	0
	Non-EE	Demand Reduction	6,802	2,411	0	4,074	0	0	0	0	317	0	0	0	0
		Deferral	171,482	0	0	0	171,482	0	0	0	0	0	0	0	0
		Total	**1,281,053**	**136,739**	**0**	**62,929**	**171,482**	**11,587**	**172,095**	**88,920**	**97,211**	**46,096**	**81,074**	**366,076**	**46,844**
2016	EE	Residential	399,334	65,614	0	5,410	0	0	82,277	50,023	37,105	20,112	1,543	115,983	21,267
		Commercial	35,633	9,151	0	702	0	0	14,076	3,648	6,434	1,454	168	0	0
		SRP	88,093	35,504	0	2,979	0	0	603	1,102	6,683	3,067	179	37,976	0
	Non-EE	Demand Reduction	5,260	3,604	0	1,224	0	0	0	0	431	0	0	0	0
		Deferral	159,412	0	0	0	159,412	0	0	0	0	0	0	0	0
		Total	**687,732**	**113,873**	**0**	**10,315**	**159,412**	**0**	**96,957**	**54,772**	**50,654**	**24,633**	**1,889**	**153,959**	**21,267**
2017	EE	Residential	452,136	88,756	0	6,076	0	0	161,506	83,545	75,765	34,962	921	0	603
		Commercial	45,507	15,495	0	1,088	0	0	15,700	4,070	7,369	1,686	101	0	0
		SRP	11,264	8,429	0	630	0	0	26	111	1,389	658	21	0	0
	Non-EE	Demand Reduction	11,423	9,993	0	1,122	0	0	0	0	308	0	0	0	0
		Deferral	148,191	0	0	0	148,191	0	0	0	0	0	0	0	0
		Total	**668,521**	**122,674**	**0**	**8,915**	**148,191**	**0**	**177,232**	**87,726**	**84,831**	**37,306**	**1,042**	**0**	**603**
Grand Total			**5,175,050**	**608,725**	**0**	**201,470**	**919,132**	**50,028**	**725,061**	**359,843**	**469,411**	**192,636**	**191,682**	**1,296,823**	**160,239**

Notes:
(1) The "EE" benefits include both Focused Energy Efficiency benefits and SRP Energy Efficiency benefits.
(2) Measures unique to SRP are listed as a separate line item under the EE heading. Measures part of the focused EE are listed in the EnergyWise and Small Business program lines.
(3) The MDC/Deferral column represents: 2012-2013: the system-average distribution benefit and 2014-2017: the calculated deferral benefit as defined in the notes section of Table S-2
(4) All benefits are in $current year except deferral benefits which are in $2014.
(5) 2012-2016 amounts have been updated to reflect year end data. 2017 amounts have been updated to reflect year end projections.
(6) Benefits due to EE reflect new installations within the year. Benefits due to Non-EE reflect cumulative installations

Table S-6
System Reliability Procurement - Tiverton/Little Compton
Demand Reduction

	Tstats	Smart Plug
Per- Event Capacity Savings per Residential Participant (kW)	**0.49**	**0.04**
Per- Event Capacity Savings per C&I Participant (kW)	**0.98**	**n/a**

	2012	2013	2014	2015	2016	2017
Number of Event Hours						
Thermostats			12	60	72	60
Plug Load Devices			6	30	36	0
Units						
Thermostats - Residential	35	167	205	232	247	247
Thermostats - C&I	0	4	4	4	4	4
Plug Load Devices	0	145	249	298	308	308
Forecasted Annual Capacity Savings (kW)	**13**	**69**	**86**	**97**	**103**	**103**
Thermostats - Residential	13	61	75	85	91	91
Thermostats - C&I	0	3	3	3	3	3
Smart Plugs	0	4	7	9	9	9
Forecasted Annual Energy Savings (kWh)	**0**	**0**	**984**	**5,560**	**7,080**	**5,623**
Thermostats - Residential	0	0	904	5,116	6,536	5,446
Thermostats - C&I	0	0	35	176	212	176
Smart Plugs	0	0	45	268	333	0
Cumulative Annual Demand Reduction Benefits ($)			**5,563**	**6,802**	**5,260**	**11,320**
Annual Energy Benefits ($)			54	317	431	362
Annual Capacity Benefits ($)			5,510	6,485	4,828	10,958

Notes:
(1) Forecasted event hours are based on an assumed three days of four-hour events, four times per year. In each event, it is assumed that the demand reduction will be staggered in two groups and cycled on and off.
(2) Savings above represent 75% of max to account for non-participation.
(2) All dollar amounts are in $current year.
(3) 2012-2017 numbers have been updated to reflect year end data.

Table S-6
System Reliability Procurement - Tiverton/Little Compton
Demand Reduction

	Tstats	Smart Plug
Per- Event Capacity Savings per Residential Participant (kW)	**0.49**	**0.04**
Per- Event Capacity Savings per C&I Participant (kW)	**0.98**	**n/a**

	2012	2013	2014	2015	2016	2017
Number of Event Hours						
Thermostats			12	60	72	48
Plug Load Devices			6	30	36	24
Units						
Thermostats - Residential	35	167	205	232	247	251
Thermostats - C&I	0	4	4	4	4	4
Plug Load Devices	0	145	249	298	308	308
Forecasted Annual Capacity Savings (kW)	**13**	**69**	**86**	**97**	**103**	**104**
Thermostats - Residential	13	61	75	85	91	92
Thermostats - C&I	0	3	3	3	3	3
Smart Plugs	0	4	7	9	9	9
Forecasted Annual Energy Savings (kWh)	**0**	**0**	**984**	**5,560**	**7,080**	**4,791**
Thermostats - Residential	0	0	904	5,116	6,536	4,428
Thermostats - C&I	0	0	35	176	212	141
Smart Plugs	0	0	45	268	333	222
Cumulative Annual Demand Reduction Benefits ($)			**5,563**	**6,802**	**5,260**	**11,423**
Annual Energy Benefits ($)			54	317	431	308
Annual Capacity Benefits ($)			5,510	6,485	4,828	11,115

Notes:

(1) Forecasted event hours are based on an assumed three days of four-hour events, four times per year. In each event, it is assumed that the demand reduction will be staggered in two groups and cycled on and off.
(2) Savings above represent 75% of max to account for non-participation.
(2) All dollar amounts are in $current year.
~~(3) 2012-2016 amounts have been updated to reflect year end data and 2017 amounts have been updated to reflect year end projections.~~

Table S-7
System Reliability Procurement - Tiverton/Little Compton
Potential for Wires Project Deferral at Year Begin

	2012	2013	2014	2015	2016	2017	2018
Cumulative Annual kW from Energy Efficiency			**239**	**342**	**475**	**559**	**619**
Focused Energy Efficiency			153	215	325	381	419
SRP Energy Efficiency			86	127	149	178	200
Cumulative Annual kW from Demand Reduction			**82**	**86**	**97**	**103**	**103**
Thermostats - Residential			74	75	85	91	91
Thermostats - C&I			3	3	3	3	3
Smart Plugs			4	7	9	9	9
Cumulative Annual kW from RFP							**13**
Total Cumulative kW Reduction From DemandLink			**321**	**427**	**572**	**662**	**735**
Total Cumulative kW Reduction Needed to Defer Wires Project			**150**	**390**	**630**	**860**	**1,000**
% Deferral Targets Achieved by DemandLink			214%	110%	91%	77%	74%

Notes:
(1) All kW amounts are Summer kW and are cumulative.
(2) This table shows the number of kW have been either installed through EE or have become available to reduce through demand reduction by the end of the previous year to therefore contribute to the deferral of the wires investment in the current year.
(3) kW in Reserve acts as insurance against customers overriding the demand reduction themselves, so that the required reduction is still met.
(4) 2012-2017 numbers have been updated to reflect year end data. 2018 numbers have been updated to reflect year end projections.

Table S-7
System Reliability Procurement - Tiverton/Little Compton
Potential for Wires Project Deferral at Year Begin

	2012	2013	2014	2015	2016	2017	2018
Cumulative Annual kW from Energy Efficiency			**239**	**342**	**475**	**556**	**612**
Focused Energy Efficiency			153	215	325	381	430
SRP Energy Efficiency			86	127	149	175	183
Cumulative Annual kW from Demand Reduction			**82**	**86**	**97**	**103**	**104**
Thermostats - Residential			74	75	85	91	92
Thermostats - C&I			3	3	3	3	3
Smart Plugs			4	7	9	9	9
Cumulative Annual kW from RFP							-
Total Cumulative kW Reduction From DemandLink			**321**	**427**	**572**	**659**	**717**
Total Cumulative kW Reduction Needed to Defer Wires Project			**150**	**390**	**630**	**860**	**1,000**
% Deferral Targets Achieved by DemandLink			214%	110%	91%	77%	72%

Notes:
(1) All kW amounts are Summer kW and are cumulative.
(2) This table shows the number of kW have been either installed through EE or have become available to reduce through demand reduction by the end of the previous year to therefore contribute to the deferral of the wires investment in the current year.
(3) kW in Reserve acts as insurance against customers overriding the demand reduction themselves, so that the required reduction is still met.
(4) 2012 -2016 amounts have been updated to reflect year end data. 2017 amounts have been updated to reflect year end projections.

Appendix 3 –Tiverton Pilot Evaluation Deliverables from Opinion Dynamics Corporation

Appendix 4 – Projects Screened for NWA

Count	Project ID	Project Description	NWA Comment	Partial NWA Comment	Capex Spending Rational	Budget Classification	Program Code	Date Initiated
1	C078460	Reconductor 3308 Substation transmission Line	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		5/18/2017
2	C078474	Franklin Square Substationstation Network Feeders	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		5/23/2017
3	C078476	Hope Substationstation Pole Replacementacement	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		5/23/2017
4	C078488	RI DFP100 Protective Relay Replacementacement Project	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		5/25/2017
5	C078596	RI 33F4 Feeder - Reconductor existing small wire with 477 spacer cable	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Reliability driven project	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	Reliability		6/15/2017
6	C078686	RI 32J12 Feeder - Ella Terrace URD Cable Replacementacement	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		6/28/2017
7	C078693	RI 18F13 Feeder - URD High Ridge Condominiums Cable Replacementacement	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		6/29/2017
8	C078695	RI 21F2 Feeder - URD Alpine Estates Cable Cure Project	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		6/29/2017
9	C078720	RI 37W42 Feeder - URD East Bay Village Apartments Cable Cure Project	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement - I&M (NE)		7/3/2017
10	C078734	Providence Study: Admiral St 4kV & 11kV Conversion	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/5/2017
11	C078735	Providence Study: New Admiral St 12kV Distribution Substationstation	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/6/2017
12	C078796	Providence Study Admiral St-Rochamb Substationstations Distribution Line	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
13	C078797	Providence Study Admiral St-Rochamb Distribution Substationstation	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
14	C078800	Providence Study Clarkson St & Lippit Hill 12kV Distribution Line	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
15	C078801	Providence Study Admiral St Demolition	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
16	C078802	Providence Study Olneyville 4kV Distribution Line	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
17	C078803	Providence Study Admiral St 12kV Manhole & Duct System	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
18	C078804	Providence Study Admiral St 12kV Cables	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
19	C078805	Providence Study Knightsville 4kV Conversion	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
20	C078806	Providence Study Knightsville 4kV Distribution Substationstation	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
21	C078810	Providence Study HarrisAve 11kV(1129&1137)	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
22	C078811	Providence Study Geneva,Olnyvile,Rocham4kV	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
23	C078847	Providence Study Geneva 4kV Substation Removal	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/18/2017
24	C078849	Providence Study Harris Ave Substation Removal	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/18/2017
25	C078850	Providence Study Olneyvile 4kV Substation Removal	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/18/2017
26	C078851	Providence Study Rochambeau 4kV Substation Removal	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/18/2017
27	C078857	Providence Study Harris Ave 4kV & 11kV Retirement	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/19/2017
28	C078921	RI Underground Cable Replacement Program - Fdr 1158	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement	UG Cable Replacements	7/31/2017
29	C078923	RI Underground Cable Replacement Program - Fdr 1160	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement	UG Cable Replacements	7/31/2017
30	C078926	RI Underground Cable Replacement Program - Fdr 1162	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement	UG Cable Replacements	7/31/2017
31	C078928	RI Underground Cable Replacement Program - Fdr 1164	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement	UG Cable Replacements	7/31/2017
32	C078931	RI Underground Cable Replacement Program - Fdr 1166	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement	UG Cable Replacements	7/31/2017
33	C078933	RI Underground Cable Replacement Program - Fdr 1168	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement	UG Cable Replacements	7/31/2017
34	C079076	Narragansett Electric Distribution Substation PLC Replacementacement	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Reliability Driven Project	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	Substation		8/24/2017
35	C079183	RI Replacementacement of ACNW Vault Vent Blowers	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		9/15/2017
36	C079234	Mobile Substationstation ID# 5616 Refurbishment & Upgrade	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Substation		9/26/2017
37	C079282	RI VVO/CVR Exp - Washington 126 Distribution Line	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Volt VAR Optimization Project	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	Reliability		10/4/2017
38	C079288	RI VVO/CVR Expansion - Staples 112 Distribution Line	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Volt VAR Optimization Project	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	Reliability		10/4/2017
39	C079300	RI VVO/CVR Exp - Washington 126 Substation	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Volt VAR Optimization Project	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	Reliability		10/6/2017
40	C079317	Providence Study Harris Av & Olneyvile Supply	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		10/9/2017
41	C079318	Providence Study Remove Rochambeau Supply	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		10/9/2017
42	C079418	Tiverton 3V0 Distribution Substation	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Programatic Ground Fault Overvoltage Protection to address accumulated Distributed Energy Resource interconnections	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	Reliability		10/30/2017
43	C079482	RI VVO/CVR Exp - Staples 112 Substation	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Volt VAR Optimization Project	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	Reliability		11/13/2017
44	C079493	Kilvert St T1 3V0 Distribution Substation	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Programatic Ground Fault Overvoltage Protection to address accumulated Distributed Energy Resource interconnections	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	Reliability		11/15/2017
45	C079525	Old Baptist Rd 3V0 Distribution Substation	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Programatic Ground Fault Overvoltage Protection to address accumulated Distributed Energy Resource interconnections	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	Reliability		11/16/2017
46	C079599	RI 155F4 Asset Replacementacement-Narragansett Way	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		12/4/2017
47	C080092	15F1 and 15F2 Getaway Relocation	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		2/21/2018
48	C080231	Kent County ARP Breaker Replacementmt	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Substation		3/22/2018

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Project ID	Project Description	NWA Comment	Capex Spending Rational	Budget Classification	Program Code	Date Initiated
C072807	RI UG Cable Replacement Program - Fdr 1102	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	Asset Condition	Asset Replacement	UG Cable Replacements	4/12/2016
C072826	RI UG Cable Replacement Program - Fdr 1104	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	Asset Condition	Asset Replacement	UG Cable Replacements	4/12/2016
C072847	RI UG Cable Replacement Program - Fdr 1106	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	Asset Condition	Asset Replacement	UG Cable Replacements	4/12/2016
C074307	RI UG 79F1 Duct Replacement Charles & Orms Sts	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	Asset Condition	Asset Replacement		6/23/2016
C074426	EMS Expansion - Franklin Sq #11	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - EMS Expansion Program	System Capacity & Performance	Reliability	EMS Expansion	6/28/2016
C074427	EMS Expansion - Phillipsdale 20	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - EMS Expansion Program	System Capacity & Performance	Relay/RTU	EMS Expansion	6/28/2016
C074428	EMS Expansion - Wampanoag 48	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - EMS Expansion Program	System Capacity & Performance	Relay/RTU	EMS Expansion	6/28/2016
C074429	EMS Expansion - Warren #5	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - EMS Expansion Program	System Capacity & Performance	Relay/RTU	EMS Expansion	6/28/2016
C074430	EMS Expansion - Wood River 85	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - EMS Expansion Program	System Capacity & Performance	Reliability	EMS Expansion	6/28/2016
C074431	EMS Expansion - Bonnet 42	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - EMS Expansion Program	System Capacity & Performance	Relay/RTU	EMS Expansion	6/28/2016
C074433	Bristol 51 - EMS Expansion	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - EMS Expansion Program	System Capacity & Performance	Reliability	EMS Expansion	6/28/2016
C074435	EMS Expansion - Centredale 50	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - EMS Expansion Program	System Capacity & Performance	Reliability	EMS Expansion	6/28/2016
C074436	EMS Expansion - Hope 15	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - EMS Expansion Program	System Capacity & Performance	Reliability	EMS Expansion	6/28/2016
C074437	Manton 69 - EMS Expansion	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - EMS Expansion Program	System Capacity & Performance	Reliability	EMS Expansion	6/28/2016
C074438	EMS Expansion - Merton 51	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - EMS Expansion Program	System Capacity & Performance	Substation	EMS Expansion	6/28/2016
C074439	EMS Expansion - Tiverton 2 #33	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - EMS Expansion Program	System Capacity & Performance	Reliability	EMS Expansion	6/28/2016
C074440	EMS Expansion - Warwick Mall 28	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - EMS Expansion Program	System Capacity & Performance	Reliability	EMS Expansion	6/28/2016
C074441	EMS Expansion - West Greenville 45	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - EMS Expansion Program	System Capacity & Performance	Reliability	EMS Expansion	6/28/2016
C074803	37K21/22 Removal, Memorial Drive Newport	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project	Asset Condition	Asset Replacement		7/22/2016
C074804	Apponaug 23kV Retirements (Distribution Substation)	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project	Asset Condition	Asset Replacement	Substation Asset Replacement	7/22/2016
C074807	Apponaug 23kV Retirements (Distribution Line)	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project	Asset Condition	Asset Replacement	Substation Asset Replacement	7/22/2016
C075328	Dyer St Indoor Sub Retirement	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project	Asset Condition	Asset Replacement		8/23/2016
C075403	Elmwood Indoor Equipment Removal	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project	Asset Condition	Asset Replacement	Substation Asset Replacement	8/26/2016
C075445	RI Royal Disconnect Replacement Program	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Program	Asset Condition	Asset Replacement		8/30/2016
C075545	Admiral 9 Sub - EMS Expansion	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - EMS Expansion Program	System Capacity & Performance	Reliability		9/7/2016
C075571	RI VVO Langworthy Corner 86, Distribution Line	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Volt-Var Optimization Project	System Capacity & Performance	Reliability		9/8/2016
C075573	RI VVO Langworthy Corner 86, Distribution Substation	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Volt-Var Optimization Project	System Capacity & Performance	Reliability		9/8/2016
C075860	Geneva Sub Equiment Replacement	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project	Asset Condition	Asset Replacement		9/23/2016
C076202	Dressler S-UG Street Light Replacement	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project	Asset Condition	Outdoor Lighting - Capital		10/7/2016
C076289	IRURD Pequaw Honk URD RI-Little Compton	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project	Asset Condition	Asset Replacement		10/13/2016
C076365	RI VVO/CVR Tiogue Ave 100, Distribution Substation	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Volt-Var Optimization Project	System Capacity & Performance	Reliability		10/18/2016
C076367	RI VVO/CVR Lincoln Ave 72, Distribution Substation	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Volt-Var Optimization Project	System Capacity & Performance	Reliability		10/18/2016
C077200	RI VVO/CVR Tiogue Ave 100, Distribution Line	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Volt-Var Optimization Project	System Capacity & Performance	Reliability		1/6/2017
C077201	RI VVO/CVR Lincoln Ave 72, Distribution Line	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Volt-Var Optimization Project	System Capacity & Performance	Reliability		1/6/2017
C077365	ProvStudy Clarkson St 13F10 Hawkins	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - See Providence Area Study - Implementation Plan, May 2017	Asset Condition	Asset Replacement		2/2/2017
C077368	ProvStudy Retire Olneyville Fdr 6J5	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - See Providence Area Study - Implementation Plan, May 2017	Asset Condition	Asset Replacement		2/2/2017