The Narragansett Electric Company
d/b/a Rhode Island Energy

System Reliability Procurement Investment Proposal for Electric Demand Response 2024-2026

February 8, 2024

Docket No. 24-06-EE

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™
a PPL company

Andrew S. Marcaccio, Counsel
PPL Services Corporation
AMarcaccio@pplweb.com

280 Melrose Street
Providence, RI 02907
Phone 401-784-4263

Rhode Island Energy™
a PPL company

February 8, 2024

VIA ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 24-06-EE – The Narragansett Electric Company's d/b/a Rhode Island Energy's System Reliability Procurement Investment Proposal for Electric Demand Response 2024-2026 - ConnectedSolutions

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed please find the Company's proposed electric demand response program ("ConnectedSolutions") for program years 2024-2026. This filing is being made as a system reliability procurement ("SRP") investment proposal pursuant to R.I. Gen. Laws § 39-1-27.7 and Chapter 5 of the Least Cost Procurement Standards. The Company respectfully requests that the Public Utilities Commission ("PUC") approve the Company's proposal for effect June 1, 2024.

The total projected programmatic budget for ConnectedSolutions, including proposed administrative funding to the Office of Energy Resources and Energy Efficiency and Resources Management Council and a performance incentive to be earned by the Company, is $9.8 Million for 2024, $10.5 Million for 2025, and $11.6 Million for 2026. The total benefits of ConnectedSolutions, based on avoided electric bill cost only, are $11.7 Million for 2024, $13.5 Million for 2025, and $15.6 Million for 2026. The Company is proposing a performance incentive to be earned by the Company equal to 20% of the total net avoided electric bill costs which equates to a targeted incentive of $472.0 Thousand for 2024, $760.8 Thousand for 2025, and $998.9 Thousand for 2026, to be reconciled based on actual peak demand reduction annually. The Company notes its intent to earmark its earned performance incentive for reinvestment in the electric distribution system.

The Company is proposing to recover the costs of ConnectedSolutions through a 2024 SRP Factor of $0.00224 per kWh applicable to electric customers for effect June 1, 2024, through December 31, 2024. The SRP Factor would be incorporated into the total electric energy efficiency charge effective June 1, 2024. For program years 2025 and 2026, the Company is proposing a 12-month SRP Factor updated each January 1st.

ConnectedSolutions will have offerings for both residential and small business ("RSB") electric participants and commercial and industrial ("C&I") electric participants. The pathways for RSB participants include Bring Your Own Thermostat ("BYOT"), RSB Battery, and Electric Vehicle Demand Response ("EVDR"). The pathways for C&I participants include Daily Dispatch and Targeted Dispatch. Each pathway is summarized below:

- **BYOT** – Participants receive an upfront enrollment incentive and a participation incentive per season for setting back their connected thermostats.

- **RSB Battery** – During peak periods, battery energy storage systems discharge electricity; participants earn an incentive based on average performance across all peak events in a season.

- **EVDR** – New for 2024-2025, the Company proposes to incentivize participants who drive electric vehicles to curtail charging during peak demand periods.

- **Daily Dispatch** – Incentivizes participants on a pay-for-performance basis to curtail their electricity demand during the one peak grid load hour of the year, as well as other high and medium peak days in June through September, for a total of no more than 60 events.

- **Targeted Dispatch** – Incentivizes participants on a pay-for-performance basis to curtail their electricity demand during the one peak load hour of the year and other high peak days in June through September, for a total of no more than eight events.

Thank you for your attention to this filing. If you have any questions, please contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

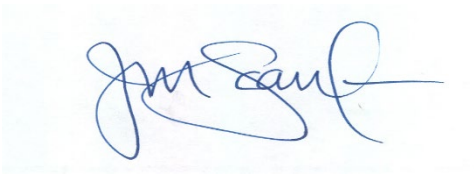
Enclosures

cc: Docket No. 24-06-EE Service List
Christy Hetherington, Esq.
John Bell, Division

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.



Joanne M. Scanlon

February 8, 2024
Date

Docket No. 24-06-EE – Rhode Island Energy System Reliability Procurement ("SRP") Investment Proposal for Electric Demand Response 2024-2026 – ConnectedSolutions
Service list 2/8/2024

Name/Address	E-mail Distribution List	Phone
The Narragansett Electric Company d/b/a Rhode Island Energy Andrew S. Marcaccio, Esq. Celia B. O'Brien, Esq. 280 Melrose St. Providence, RI 02907	AMarcaccio@pplweb.com;	401-784-4263
	JHutchinson@pplweb.com;	
	COBrien@pplweb.com;	
	JScanlon@pplweb.com;	
	ARArchambault@RIEnergy.com;	
	SBriggs@pplweb.com;	
	KRCastro@RIEnergy.com;	
	RConstable@RIEnergy.com;	
	BSFeldman@RIEnergy.com;	
	KWGauntner@pplweb.com;	
	CAGill@RIEnergy.com;	
	RLGolding@RIEnergy.com;	
	LKurdgelashvili@pplweb.com;	
	DMMoreira@RIEnergy.com;	
	JEReno@rienergy.com;	
	BESchuster@RIEnergy.com;	
Division of Public Utilities and Carriers Margaret L. Hogan, Esq.	Margaret.L.Hogan@dpuc.ri.gov;	401-784-2120
	Christy.hetherington@dpuc.ri.gov;	
	john.bell@dpuc.ri.gov;	
	Joel.munoz@dpuc.ri.gov;	
	Ellen.golde@dpuc.ri.gov;	
	Paul.Roberti@dpuc.ri.gov;	
Tim Woolf Jennifer Kallay **Synapse Energy Economics**	twoolf@synapse-energy.com;	
	jkallay@synapse-energy.com;	

22 Pearl Street Cambridge, MA 02139		
Office of Energy Resources (OER) Albert Vitali, Esq. Dept. of Administration Division of Legal Services One Capitol Hill, 4th Floor Providence, RI 02908	Albert.Vitali@doa.ri.gov; Nancy.Russolino@doa.ri.gov; Christopher.Kearns@energy.ri.gov; Steven.Chybowski@energy.ri.gov; William.Owen@energy.ri.gov; Nathan.Cleveland@energy.ri.gov; Karen.Bradbury@energy.ri.gov;	401-222-8880
Original & 9 copies file w/: Luly E. Massaro, Commission Clerk John Harrington, Commission Counsel Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; John.Harrington@puc.ri.gov; Alan.nault@puc.ri.gov; Todd.bianco@puc.ri.gov ;	401-780-2107
Marisa Desautel, Esq. Desautel Browning Law	marisa@desautelbrowning.com;	401-477-0023
Larry Chretien	Larry@massenergy.org;	
Acadia Center Emily Koo, Director	EKoo@acadiacenter.org;	

JOINT PRE-FILED DIRECT TESTIMONY

OF

BRETT FELDMAN,

ALLISON ARCHAMBAULT,

JESSICA RENO,

LADO KURDGELASHVILI,

AND

CARRIE GILL

Table of Contents

I. Introduction

Brett Feldman

Q. Mr. Feldman, please state your name and business address.

A. My name is Brett Feldman. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. By whom are you employed and in what position?

A. I am employed by The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company"), which is a subsidiary of PPL Corporation ("PPL"), as Manager, Customer Energy Management ("CEM"), Rhode Island. In this role, I lead the teams responsible for the Company's energy efficiency strategy, policy, and planning in Rhode Island.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Arts in Economics from University of Michigan and a Masters in Business Administration from Boston University. I have been in my current position since 2022. Prior to joining Rhode Island Energy, I worked at Guidehouse (formerly Navigant), performing market research and consulting on global energy efficiency and demand response program strategy, evaluation, and policy engagements; Constellation Energy, managing demand side resource portfolios in wholesale markets including ISO-

NE, NYISO, and PJM; Eversource Energy, managing commercial and industrial ("C&I") energy efficiency and demand response program implementation; Nexant, consulting on utility energy efficiency and demand response program design and evaluation; and ICF, providing economic and marketing support to US Environmental Protection Agency's ("EPA") ENERGY STAR® program.

Q. Have you previously submitted testimony on behalf of Rhode Island Energy?

A. Yes. I testified before the PUC relating to the Company's 2023 and 2024 Annual Energy Efficiency and Conservation Procurement Program Plans (Docket Nos. 22-33-EE and 23-35-EE).

Allison Archambault

Q. Ms. Archambault, please state your name and business address.

A. My name is Allison Archambault. My business address is 280 Melrose Street, Providence, Rhode Island, 02907.

Q. By whom are you employed and in what position?

A. I am employed by Rhode Island Energy as a Senior Program Manager of Electric Transportation and Demand Response within the Customer Service team. In this role, I am responsible for program management, development, and customer service, including

providing strategic support to inform business decisions that advance safe, reliable, affordable electricity distribution.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science in Environmental Studies from William Smith College in 2006 and a Master of Science in Sustainable Development and Climate Change from Antioch University New England in 2013.

Prior to my role with Rhode Island Energy, I served multiple roles within the Rhode Island Department of Environmental Management from 2013 to 2023, culminating my service as a Supervising Air Quality Specialist. In that role, I provided oversight of regulatory programs including the Regional Greenhouse Gas Initiative ("RGGI"), Rhode Island's Low Emission and Zero-Emission Vehicle Programs, and the Rhode Island Motor Vehicle Inspection and Maintenance Program. I also provided oversight of climate policies and programs working to reduce and inventory carbon emissions which are prudent to meet the mandates set by the 2021 Act on Climate. Prior to 2013, I served as a Peace Corps Volunteer as a Community Based Environmental Manager in Peru.

Q. Have you previously submitted testimony on behalf of Rhode Island Energy?

A. No.

Jessica Reno

Q. Ms. Reno, please state your name and business address.

A. My name is Jessica Reno. My business address is 280 Melrose Street, Providence, Rhode Island, 02907.

Q. By whom are you employed and in what position?

A. I am employed by Rhode Island Energy as an Engineer for the Energy Efficiency Strategy, Policy, and EMV Reporting Team. In this role, I am responsible for program management, demand response development, and oversight of the Company's resources participating in ISO-NE's Forward Capacity Market.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science in Mechanical Engineering from Pennsylvania State University in 2023. Prior to my role with Rhode Island Energy, I worked as an Engineering Intern for PPL's Reliability Team located in Harrisburg, PA. During this internship, I analyzed grid infrastructure quality and performance to increase overall reliability of the Harrisburg/Lancaster distribution system. In addition, I researched PPL's grid modernization efforts and worked with my fellow peers to assess and identify new utilizations for Advanced Metering Infrastructure ("AMI") on the electric distribution and transmission system.

Q. Have you previously submitted testimony on behalf of Rhode Island Energy?

A. No.

Lado Kurdgelashvili

Q. Dr. Kurdgelashvili, please state your name and business address.

A. My name is Lado Kurdgelashvili. My business address is 280 Melrose Street, Providence, Rhode Island, 02907.

Q. By whom are you employed and in what position?

A. I am employed as a Senior Energy Request for Proposals ("RFP") Specialist for PPL Services Corporation ("PPL Services"). In this role, I am responsible for co-managing the open enrollment process for the Renewable Energy Growth Program. In addition, I support Rhode Island Energy Last Resort Service procurement, the Offshore Wind Program, the Long-Term Contracting Standard for Renewable Energy, as well as other support functions in the energy procurement group.

Q. Please describe your educational background and professional experience.

A. I received a doctorate in Energy and Environmental Policy from the University of Delaware in 2009. I also hold Master of Science degrees in Renewable Energy and the Environmental from the University of Reading, United Kingdom, and a Bachelor of

Science in Microelectronics and Semiconductor Devices from the Georgian Technical University, Republic of Georgia.

After completing my doctorate studies, I joined a research faculty at the University of Delaware. I taught graduate and undergraduate courses, and supervised research projects. I produced numerous reports and research publications on energy and climate issues. In 2018, I left the university to pursue a career in consulting. I was contracted by Advisian, which is a consulting branch of Worley Group, where I conducted techno economic analysis of distributed and microgrid systems for numerous clients across the globe. In 2021, I was contracted by Liberty Utilities where I explored opportunities for distributed energy solutions at their water, natural gas, and electric facilities. In January 2023, I joined PPL Services as a Senior Energy RFP Specialist, which is the position I currently hold.

Q. Have you previously submitted testimony on behalf of Rhode Island Energy?

A. No.

Carrie Gill

Q. Dr. Gill, please state your name and business address.

A. My name is Carrie Gill. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. By whom are you employed and in what position?

A. I am employed by Rhode Island Energy as Senior Manager of Electric Regulatory Strategy within the External Affairs team. In this role, I am responsible for general regulatory matters, policy development, and filings. I am a strategic advisor to business teams.

Q. Please describe your educational background and professional experience.

A. I received a doctorate in environmental and natural resource economics from the University of Rhode Island in 2017, masters degrees in business administration and oceanography from the University of Rhode Island in 2010, and a bachelors of science in physics and mathematics from Loyola University, Maryland in 2007.

Prior to my role with Rhode Island Energy, I served multiple positions with the Rhode Island Office of Energy Resources from 2017 to 2022, culminating my tenure as chief economic and policy analyst. In that role, I provided strategic oversight of clean energy

and climate policies and programs for the State of Rhode Island. Prior to 2017, I held various research and teaching assistantships within University of Rhode Island (2012-2017); provided independent consulting to a solar thermal developer in Washington, DC (2012); served as a Knauss Fellow within the U.S. Department of Energy's Wind and Water Power Program (2011-2012); and supported the Coastal Resources Center with research on coastal community climate adaption (2010).

Q. Have you previously submitted testimony on behalf of Rhode Island Energy?

A. Yes, I testified on behalf of Rhode Island Energy in Docket No. 3628 (Service Quality Adjustment Plan), Docket No. 23-05-EL (Tariff Advice to Amend the Net Metering Provision), Docket No. 22-56-EL (Grid Modernization Plan), and Docket Nos. 23-44-REG and 22-39-REG (Renewable Energy Growth Program).

II. <u>Purpose and Requested Rulings</u>

Q. What is the purpose of your joint testimony?

A. The purpose of our joint testimony is to present the Company's proposed electric demand response program (branded "ConnectedSolutions") for calendar years 2024-2026 for Rhode Island Public Utilities Commission ("Commission") review and approval in accordance with the Least-Cost Procurement ("LCP") Statute (R.I. Gen. Laws § 39-1-27.7) and LCP Standards (as approved in Docket No. 23-07-EE).

Q. What rulings is the Company requesting from the Commission with this filing?

A. The Company respectfully request the Commission make the following rulings:

1. To approve the Company's proposed electric demand response System Reliability Procurement ("SRP") Investment Proposal for three (3) program years (2024, 2025, and 2026), with the first program year commencing on June 1, 2024;
2. To approve the proposed 2024 SRP Factor of $0.00224 per kWh applicable to electric customers for effect June 1, 2024, through December 31, 2024, and direct the Company to incorporate the SRP Factor into the total electric energy efficiency charge effective June 1, 2024.
3. To direct the Company to submit a compliance filing by November 22, 2024, detailing the 2024 results of the ConnectedSolutions program including, at a minimum, a comprehensive account of program expenditures, number of participating customers, incentives provided to customers, and electric savings in dollars and volumes by customer.
4. To direct the Company to submit a reconciliation filing by November 22, 2024, which reconciles the 2024 program year (which occurs during the summer) and proposes a 2025 SRP Factor, which would be a 12-month factor, for effect January 1, 2025, and would be incorporated into the total electric energy efficiency charge effective January 1, 2025. The same process to repeat for 2026.

5. To approve the Company's proposed performance incentive mechanism with a target performance incentive totaling $472.0 thousand for 2024, $760.8 thousand for 2025, and $998.9 thousand for 2026, to be reconciled based on actual peak demand reduction.
6. Make any other such rulings as may be just and proper under the circumstances.

Q. Are you sponsoring any schedules within this supplemental testimony?

A. Yes, we are sponsoring:

- Schedule 1: Rhode Island Energy's proposed *System Reliability Procurement ("SRP") Investment Proposal for Electric Demand Response 2024-2026*
- Schedule 2: Benefit-Cost Assessment (Excel File)
- Schedule 3: Summary and Response to Stakeholder Comments

Q. How is this testimony organized?

A. Section I introduces the witnesses. Section II provides the purpose of the joint testimony and the request for rulings. Section III provides updated and specific information in compliance with LCP Standards 5.3.A.i.b. In Section IV, the Company describes the contextual background for its proposal, including specific reasoning for and context of its proposed program design modifications from prior years. Section V discusses the Company's assessment of its proposal's compliance with LCP Standards. Section VI

summarizes the cost of this SRP Investment Proposal, funding source, and cost recovery. The Company concludes in Section VII.

III. Updated and Specific Information Relevant per LCP Standards 5.3.A.i.b

Q. Please provide updated and specific information relevant to LCP Standards 4.4.A.ii.a through d.

A. The specific system need is serving peak demand through lower cost investments. This system need was identified through electric forecasting, distribution system planning, and analysis of cost comparison between the proposal herein and the cost to serve peak demand. The proposal covers the system need in 2024 through 2026.

This proposal specifically addresses the system need to serve peak demand affordably by providing incentives to participating customers to reduce peak demand. Although the Company's proposal only extends through 2026, the Company anticipates this system need to exist indefinitely and will file SRP investment proposals accordingly when there is reasonable expectation that peak demand can be served more affordably through System Reliability Procurement, in alignment with the purpose of Least-Cost Procurement, in compliance with the LCP Standards, and advancing the goals of the electric system.

The Company proposes cost recovery through a volumetric SRP Factor to be included in the total electric Energy Efficiency Charge for all electric customers. Although this is the first proposal for cost recovery for ConnectedSolutions through an SRP Factor, prior cost recovery has been through the Energy Efficiency Program Charge Factor (e.g., Docket No. 22-33-EE).

Q. Please provide updated and specific information relevant to LCP Standards 4.4.A.iv.

A. The Company proposes to procure market-sourced system reliability procurement (i.e., peak demand reduction) through a pay-for-performance based program called ConnectedSolutions. The Company will also conduct a competitive solicitation for an implementation vendor in 2024.

Q. Please provide updated and specific information relevant to LCP Standards 4.4.A.v.

A. In the Company's proposal, the Company has evaluated peak demand reduction pathways based on unit cost; the Company proposes to procure the most peak demand reduction from the lowest cost pathways.

IV. Contextual Background

Q. What terminology is helpful to define for the purposes of this testimony?

A. Program refers to the entirety of ConnectedSolutions.

Track refers to the set of pathways for either Residential and Small Business ("RSB") customers or Commercial and Industrial ("C&I") customers.

Pathway refers to each distinct way for customers to participate in the Program and thereby earn incentives for peak demand reduction. The C&I Track contains the pathways Targeted Dispatch and Daily Dispatch. The RSB Track contains the pathways Bring Your Own Thermostat ("BYOT"), Electric Vehicle Demand Response ("EVDR"), and Battery ("RSB Battery").

Customer refers to a person or organization that holds an account for electricity service with the Company.

Participant refers to a customer that is enrolled in ConnectedSolutions. The set of participants is a subset of customers.

Unit Cost refers to the price to procure one unit (i.e., 1 kW) of peak demand reduction.

Lower than the best alternative Utility Reliability Procurement refers to the LCP standard described in LCP Standards 1.3.H.

Willingness to Pay is the maximum price the Company is willing to pay for a unit of peak demand reduction, where "pay" more specifically refers to the amount of money collected from all customers and then provided to program participants.

Q. What is the objective of ConnectedSolutions?

A. The objective of ConnectedSolutions is to reduce regional coincident peak demand.

Q. Does the method of peak demand reduction result in any difference in the unit of peak demand reduced?

A. No. Units of peak demand reduced are identical in serving the program objective, regardless of method by which that peak demand reduction result. A kW of peak demand reduction resulting from changing a thermostat setting is the same as a kW of peak demand reduction resulting from deferral of a manufacturing shift. There may be other value streams that are different across methods of peak demand reduction – such as battery participation in ancillary service markets or jobs associated with participant acquisition – but those differences present themselves in parallel with peak demand reduction and are not express objectives of ConnectedSolutions. Although these corollary values are important, they are out of scope for the Company's determination of its willingness to pay for peak demand reduction. Rather, the Company considers these

corollary values in a more qualitative way, for example, in modifying program design to align with LCP Standards.

Q. Please provide an example.

A. Multiple stakeholders provided public comment at a meeting of the Rhode Island Energy Efficiency and Resource Management Council ("EERMC" or "Council") on January 25, 2024, regarding the impacts of the Company's draft proposal for promptly decreasing incentive rates for the RSB Battery pathway. These comments made clear that the Company's draft proposal would have led to significant disruptions in the market which would negatively affect local battery developers and installers, as well as customers who are currently in the process of installing a battery. These disruptions would have been arguably inconsistent with the LCP Standard of reliability.[1] Therefore, the Company revised its proposal to delay the cutover date from the old incentive rate to the new incentive rate. This revision provides more time for battery developers and installers to account for and communicate new rates to their customers over the four-to-six-month lead time of customer acquisition. In this example, the Company considered the corollary value of having a healthy battery market qualitatively in influencing program design.

[1] From the LCP Standards: reliability includes the assessment of "potential for implementation issues, including available workforce, market continuity, program scalability" (1.3.D).

Q. Please summarize how customers participate in ConnectedSolutions.

A. ConnectedSolutions is a pay-for-performance program whereby the Company compensates participants for reducing their electricity demand during certain times and dates (referred to as "peak events"). For all ConnectedSolutions pathways, participating customers always have the option to opt out of a peak event. The program model is that participants "bring their own devices" – Rhode Island Energy does not incentivize the purchase of new equipment through ConnectedSolutions. For example, customers may receive an incentive for an eligible thermostat through Rhode Island Energy's energy efficiency program and then enroll in the ConnectedSolutions BYOT pathway.[2]

Q. What was the Company's general approach to program design for 2024-2026?

A. The Company generally considered ConnectedSolutions as an economic-based procurement of peak demand reduction.[3] The Company's general approach to program design was first to set the Company's willingness to pay for peak demand reduction as determined by avoided electric bill cost ("AEBC"), then to assess and refine each pathway such that unit costs are less than willingness to pay and to comply with the LCP

[2] Benefits associated with energy savings are attributed to the energy efficiency program and benefits related to demand savings are attributed to ConnectedSolutions; participant costs and purchase incentives are accounted for within the energy efficiency program. The Company assigns these values to each program separately to avoid double-counting costs and benefits.

[3] Please see the Technical Appendix in Schedule 1 for more detailed discussion of this approach.

Standards, and finally to review the program as a whole for opportunities for improved clarity or other improvement.

Q. Is the Company proposing any modifications to program design for ConnectedSolutions relative to how the program operated in 2023? If so, please summarize those proposed modifications.

A. Yes. The Company is proposing some modifications to program design for ConnectedSolutions in 2024-2026 relative to how the program operated in 2023. These modifications are primarily related to (1) revising incentive levels and HEAT loan eligibility, (2) requesting approval for three years of program implementation rather than one year, and (3) adding an additional technology pathway for residential and small business participants. The Company further describes proposed modifications for each pathway within this testimony.

Q. How did the Company engage with stakeholders in the development of its proposal?

A. The Company engaged with stakeholder members of its SRP Technical Working Group; requested feedback via the Rhode Island Office of Energy Resources' "Solar Stakeholder" email distribution list; held discussions with Curtailment Service Providers ("CSPs") and battery developers and installers; and gave presentations, held discussion, and heard public comments made at meetings of the EERMC. Schedule 3 further

describes the instances of stakeholder engagement and includes written comments submitted to the Company.

Q. LCP Standards 6.3.G states that the Council "may determine its endorsement or opposition, involvement or abstention, or any other level of action related to the filing on a case-by-case basis." What action, if any, did the Council take regarding the Company's proposal?

A. Rhode Island Energy presented its proposed program design to the Council at their meeting on January 25, 2024. At this meeting, the Council also heard public comment from several stakeholders regarding the Company's proposed modifications to two pathways, C&I Daily Dispatch and RSB Battery. The Council did not take any action.

Q. Did the Company make any further edits to its proposal resulting from the Council's meeting?

A. Yes. The proposal filed as Schedule 1 is further revised relative to the proposal submitted to the Council and discussed at their January 25, 2024, meeting as a result of discussion at the Council's meeting. Specifically, the Company extended its proposed cutover date from old incentive rates to new rates for Daily Dispatch and RSB Battery pathways, refined the proposed new incentive rates, clarified its proposed multiyear incentive rate,

and opened the option for customers on the C-06 rate to participate in either (but not both) track. The Company elaborates on these modifications in its testimony below.

IV. a. <u>Setting willingness to pay</u>

Q. How did the Company set its willingness to pay?

A. The Company set its willingness to pay based on plausible avoided electric bill costs; this analysis is described in detail in the Technical Appendix included in Schedule 1. To summarize, the Company identified the value of reducing 1 kilowatt ("kW") of peak load relative to the cost of serving 1 kW of peak load as funded through customer electric bills. This avoided electric bill value is primarily from avoided capacity costs and associated intrastate capacity demand reduction induced price effect ("DRIPE"), avoided regional network service ("RNS") charges, and avoided infrastructure (transmission and distribution) costs. For example, on average, serving 1 kW of peak load in 2024 would cost the customer base approximately $263.

Q. Please discuss avoided distribution costs specifically.

A. The Company uses a range of avoided distribution costs of $120/kW +/- $40/kW (2024 dollars). Of total avoided electric bill costs, avoided distribution cost is the largest component; this is also the component that has shown the most volatility in recent years. Consistently using the methodology recommended by Synapse through their Avoided

Energy Supply Cost study,[4] avoided distribution costs ranged between $80/kW and $174/kW from 2021 to 2024. Importantly, this methodology produces a proxy for average distribution cost to serve 1 kW. This proxy is imperfect and imprecise; absent an electric power system engineering analysis to determine distribution infrastructure investment needed to serve a specific amount of peak load at a specific location, the counterfactual of serving peak demand across the jurisdiction is not observable. The Company set its avoided distribution cost at $120/kW +/- $40/kW to generally reflect a range of plausible values evident in the range of cost estimates from 2021-2024.[5]

Q. Why did the Company use intrastate capacity DRIPE instead of interstate capacity DRIPE?

A. The Company used intrastate rather than interstate capacity DRIPE to represent the price impact on the capacity market felt by its Rhode Island customers.

IV. b. <u>Determining unit cost</u>

Q. What is a unit cost?

A. The unit cost is the price paid to reduce each unit (e.g., kW) of peak demand. Unit cost is comprised of the cost of the incentive per unit, the cost of financing (if available) per

[4] Avoided Energy Supply Components in New England: 2021 Report

[5] This range is for planning purposes and is not intended to imply larger (or smaller) values are not possible.

unit, the cost of administration per unit, and any other costs associated with procuring each unit of peak demand.[6] The Company determined a unit cost for each pathway.

Q. How did the Company determine the price to administer ConnectedSolutions per kW?

A. Administration costs include costs of staff resources and vendor/implementation contractor support. The Company aggregated administration costs by track and then divided the total cost per track by the proposed quantity of peak reduction procured per track, resulting in an administrative unit cost (measured in $/kW). Generally, the unit cost of administration of the Commercial and Industrial track is lower than the unit cost of administration of the Residential and Small Business track. This is due in part to the relative differences in total cost of administration between tracks and in part to the quantity of peak demand reduction procured per track. Administrative unit costs should be considered to be an imperfect estimate because they are constituent fixed costs divided by planned peak demand to be procured; actual administrative unit costs depend on actual peak demand reduction achieved.

[6] There is also a 3 percent of program cost allocation to the Rhode Island Office of Energy Resources ("OER") and the Council per R.I. Gen. Laws § 39-2-1.2.

Q. How did the Company determine the incentive unit cost for each pathway?

A. The incentive unit cost is the amount of incentive payment delivered to the participant for a unit of peak demand reduction. The pathways in the C&I track are unitized in program design (e.g., participants of the Targeted Dispatch pathway are compensated $35 per kW of peak demand reduced). The Company used statistics on average peak demand reduction per device to determine the incentive unit cost in the RSB track: 0.32 kW per electric vehicle, 0.65 kW per thermostat, and 5.84 kW per battery.[7] The Company divided the incentive per device by the peak demand reduction per device to calculate the incentive per unit ($/kW). For the BYOT and EVDR pathways, which both offer an upfront enrollment incentive, the Company calculated incentive unit cost separately for first-time participants and repeat participants.

Q. How did the Company determine the financing unit cost for each pathway?

A. The RSB Battery pathway is the only pathway for which financing is available. There are three cost components for financing: a monthly administrative charge, a fee per loan, and the interest buy-down cost per loan. The Company considered financing costs to be sunk for all battery participants except for participants in their first year. The Company proposes to offer the financing incentive to five customers each year based on income

[7] Statistics from Rhode Island Energy's implementation vendor based on actual performance in 2023. Battery incentives are provided in a $/kW basis.

eligibility; this is a value of $844/kW in the first year of participation for those participants who receive the financial incentive. For the purposes of program design, the Company spreads this financing cost across all kW planned to be procured from first-time participants each year. The financing unit cost ranges from $22/kW to $472/kW, where the range is driven by the number of expected recipients in the numerator and the range of kW reduced by the RSB pathway in the denominator.

Q. Please summarize the unit cost across all pathways.

A. Targeted Dispatch has the lowest unit cost, followed by repeat participation in the BYOT and EVDR pathways. First-year participation in BYOT and EVDR pathways are the next lowest cost. Daily Dispatch has the second highest unit cost and the RSB Battery pathway has the highest unit cost.

Q. How do these unit costs factor into the Company's proposed program design?

A. These unit costs factor into the proposed program design in two ways. First, the Company generally proposes to procure more of lower-cost peak demand reduction and less of higher-cost peak demand reduction. Second, the Company proposes modifications to incentive levels and program design intended to reduce unit costs of pathways that are higher than the Company's willingness to pay for peak demand reduction.

IV. c. Targeted Dispatch

Q. Please summarize the proposed modifications to the Targeted Dispatch pathway.

A. The Company proposes to reduce the incentive level from $40/kW to $35/kW to be consistent with years prior to 2023 and cap the total incentive allowed per customer to $1,000,000 per year.[8] The company is also proposing additional permitting requirements for fossil fuel-based generators participating in the C&I track to align with the LCP Statutes and Standards. Section V.e. details the additional generator requirements.

Q. How did the Company determine the quantity of peak demand reduction to procure through Targeted Dispatch?

A. Recognizing that peak demand reduction through Targeted Dispatch is the least-cost way to procure peak demand reduction, the Company allowed for unconstrained growth in program participation. The Company forecasted growth based on the linear trend of actual peak reduction achieved in 2021-2023.

[8] This incentive cap is applied in aggregate across incentive earned in both the Targeted Dispatch and Daily Dispatch pathways.

Q. How did the Company account for the proposed reduction in incentive in its forecasted participation?

A. The Company accounted for the proposed reduction in incentive by relying more on the change in kW contracted from 2021 to 2022 (when the incentive rate was $35/kW) than from 2022-2023 (when the incentive rate increased from $35/kW to $40/kW). The Company considers growth from 2021-2022 to be an adequate proxy for growth in 2023-2024, 2024-2025, and 2025-2026.

IV. d. BYOT

Q. Please summarize the proposed modifications to the BYOT pathway.

A. Recognizing that peak demand reduction through the BYOT pathway is the second lowest cost peak demand reduction, the Company proposes to increase the upfront enrollment incentive to encourage more participation in future years by repeat participants, thereby providing a growing source of low-cost peak demand reduction.

Q. How did the Company determine the quantity of peak demand reduction it proposes to procure through this pathway?

A. In consultation with its implementation vendor, the Company decided to pursue an ambitious participant acquisition strategy: enrolling 4,000 new devices per year. The

Company's strategy to achieve this level of participant growth is through doubling the upfront enrollment incentive and increasing program marketing.

IV. e. <u>Electric Vehicle Demand Response (EVDR)</u>

Q. Please summarize this pathway.

A. The Company is proposing a new pathway for Residential and Small Business customers – electric vehicle demand response. Participants will earn a $50 upfront enrollment incentive and a $20/season participation incentive.

Q. Why is this Company proposing this pathway?

A. The Company is proposing this pathway to develop lower-cost peak demand reduction and leverage the growing penetration of electric vehicles ("EVs") in Rhode Island.

Q. How is this pathway different from the Company's prior off-peak charging rebate program branded "Smart Charge RI"?

A. This pathway is different because Smart Charge RI provided participants an incentive for charging their vehicles during off-peak window from 9:00 p.m. to 1:00 p.m. – when demand for electricity is the lowest. Smart Charge RI was a behavioral (or passive) managed charging program, which incentivized and nudged desired charge schedules. In contrast, the ConnectedSolutions EVDR pathway takes an actively managed charging

approach, which actively manages EV loads by remotely curtailing charge hours. The Company anticipates filing a proposal for Phase II of its Electric Transportation Initiative that includes an expanded off-peak charging rebate pilot. Participants will only be allowed to participate in either the EVDR pathway or the off-peak charging rebate program; participants may not participate in both programs to avoid paying duplicate incentives for the same benefit. The Company will communicate these details to potential participants in program materials.

Q. How did the Company determine the quantity of peak demand reduction to procure through the EVDR pathway?

A. According to insights from the Company's implementation vendor and other vendors in this space, typically 15 percent of total EVs registered in a state participate in a utility offered program. Even with EV registration growth expected to climb over the course of program implementation, the Company decided to pursue a 5-15 percent participant acquisition strategy to be conservative in launching this new pathway. As of October 2023, there were 8,538 EVs registered in Rhode Island,[9] which suggests there is a pool of ~500-1,280 participants for the 2024 season, before accounting for participant acquisition lead time. The Company proposes to scale the EVDR pathway by 500 new participants in 2024; 750 new participants in 2025; and 1,000 new participants in 2026. The Company's

[9] Source: S&P Global (Formerly IHS Markit) October 2023 registration data.

strategy to achieve this level of participant growth is also based on the Electric Transportation Phase I Initiative that included the Smart Charge RI off-peak charging rebate pilot, which included over 500 participants at that time.

IV. f. Daily Dispatch

Q. Please summarize the proposed modifications to this pathway.

A. The Company proposes to reduce the incentive rate from $300/kW to $275/kW and cap the total incentive allowed per customer to $1,000,000 per year. [10] The company is also proposing additional permitting requirements for fossil fuel-based generators participating in the C&I track to align with the LCP Statutes and Standards. Section V.e. details the additional generator requirements.

Q. What is the reasoning behind reducing the incentive rate?

A. The Company proposes to reduce the incentive rate to bring the cost of procuring peak reduction through Daily Dispatch more in line with the avoided electric bill cost, in order to provide more value to the entire customer base.[11] Although the majority of peak

[10] This incentive cap is applied in aggregate across incentive earned in both the Targeted Dispatch and Daily Dispatch pathways.

[11] A prior version of the Company's proposal indicated the proposed change in incentive level was to match incentive levels in neighboring states. Further discussion with stakeholder illuminated that other states have additional incentive streams (e.g., incentives through the SMART program in Massachusetts, designed to support their Clean Peak Standard). However, further analysis suggests this change is necessary to bring unit costs to procure peak demand reduction in line with value in terms of avoided electric bill costs.

demand reduction strategies that participants employ in Daily Dispatch are load shed or behavioral load shifting, there is growing interest in battery energy storage as a means to participate in Daily Dispatch. The Company heard from stakeholders that these battery systems have long lead times and that sudden changes in incentive levels can disturb the market. Therefore, the Company proposes a cutover date to new incentives on June 1, 2024; participants that enroll in ConnectedSolutions prior to June 1 (or who receive a Commitment Letter) will receive the $300/kW incentive rate.

Q. How did the Company account for energy price arbitrage from charging the battery during lower-cost times and discharging the battery during higher-cost times?

A. The Company averaged wholesale energy prices for the 90 highest-cost hours and the remaining hours of each year 2021-2023. Assuming 85 percent round-trip efficiency, the Company calculated the average cost to charge a battery off-peak compared to procuring supply during the high-cost peak hours and normalized this average cost differential by kW. The Company estimates the value of energy price arbitrage was about $13/kW on average in 2021-2023 and notes interannual volatility in the value of energy price arbitrage.

Q. How should the Company account for local distribution value of large batteries that participate in the Daily Dispatch pathway?

A, The Company accounts for an average avoided distribution infrastructure cost in its willingness to pay for peak demand reduction; the value of avoided distribution infrastructure cost is equal across pathways. The Company does not account for any incremental distribution system value from batteries that participate in the Daily Dispatch pathway because (1) these services are not guaranteed nor solicited, (2) there is no contractual obligation on which the Company can rely, (3) the Company does not have the requisite hardware or software at this time to monitor and manage batteries to provide local distribution value, and (4) services for specific distribution infrastructure deferral are procured through specific Requests for Procurement for non-wires solutions and not through ConnectedSolutions.

Q. What is the reasoning for the Company's proposed application of a cap on incentive amount attainable per participant?

A. The Company is proposing this incentive cap because (1) it is not comfortable allocating more than 10 percent of its annual budget to a single participant and (2) allocating a substantial portion of the budget to a single participant without a guarantee of expected performance with associated penalty for non-performance (a) makes managing and

executing on budgets difficult and (b) puts a disproportionate share of risk onto customers that fund this program.

Q. Are there any scenarios in which the Company would potentially be amenable to providing an incentive greater than $1,000,000 to a single participant?

A. The Company would be open to exploring a larger contract for procuring peak demand reduction through a competitive process, such as an open Request for Proposals or an auction with a pre-determined ceiling price. Any resulting contracts would need to have a performance guarantee and associated penalty for non-performance. The Company is not proposing such a process within this SRP Investment Proposal but invites further feedback from parties and stakeholders regarding this concept.

Q. What is the reasoning for the Company transitioning from a "five-year rate lock" to a "multiyear incentive rate"?

A. The Company is transitioning from a "five-year rate lock" to a "multiyear incentive rate" to provide due transparency about possible variations in expected revenues for potential participants making financial decisions.

Q. Please explain the importance of and difference between a "five-year rate lock" and a "multiyear incentive rate."

A. Stakeholders have noted the importance of expected cash flows in financial planning and procurement decisions for some demand response investments, like battery energy storage systems.

In prior program years, the Company had advertised a "five-year rate lock" whereby participants could expect to receive the same incentive levels as their first year of enrollment in years two through five. Although the Company intended and continues to intend to honor five years of consistent incentive rates, the Company obtained funding for ConnectedSolutions on a more frequent annual basis. The term "five-year rate lock" obscured this annual proposal and approval process, which introduced risk into the market for years beyond the annual regulatory approved year.

The Company is attempting to provide more clarity and transparency with transitioning to the term "multiyear incentive rate." By removing the work "lock," the Company intends to make it clearer that incentive levels offered past the current proposal are subject to change. Although the Company intends to maintain incentive levels for five years from the year of enrollment, the Company reserves the right to amend incentive levels if warranted. To offset potential perceived reduction in certainty from potential participants,

the Company is extending the duration for which it is proposing and requesting approval for ConnectedSolutions (three years instead of one year).

Q. Is the Company proposing to honor the "five-year rate lock" for existing participants?

A. Yes, the Company is proposing to honor the "five-year rate lock" for participants for five years following enrollment. More information is available in Schedule 1.

Q. For how many years is the Company proposing a multiyear incentive rate?

A. The Company proposes its incentive rates to be the same for five years from the first year of participation for new participants in ConnectedSolutions, subject to and in compliance with the normal proposal and oversight process and LCP Standards.

Q. What is the basis for not offering a longer-term multiyear incentive rate?

A. The Company is not comfortable with proposing a longer-term incentive at this time. The Company is attempting to balance mitigating risk for potential participants (by offering a multiyear incentive) with mitigating risk for customers stemming from changes in avoided electric bill value associated with peak demand reduction procured through ConnectedSolutions. The Company considers five years to be appropriate at this time.

Q. Have any customers requested a Commitment Letter at this time?

A. No. The Company has not received any requests for Commitment Letters.

Q. How did the Company determine the quantity of peak demand reduction to procure through Daily Dispatch?

A. The Company determined its procurement quantity based on an expectation of maintaining the same level of peak demand reduction in prior years, with minimal attrition and attenuation to account for the lower incentive rate and incentive cap, plus a 10 percent year-over-year growth of first-time participants throughout 2024-2026.[12] Although there has been some discussion of large battery development for potential C&I participants, the Company has yet to receive a request for a Commitment Letter for any such system. Given the proposed decrease in incentive rate and the proposed incentive cap, the Company's proposed quantity is robust to scenarios in which fewer large batteries are deployed than otherwise in a counterfactual world of a higher incentive level and unconstrained earning potential.

[12] Actual peak demand reduction grew by 15 percent from 2022 to 2023; assuming 10 percent growth is comparatively more conservative to account for lower incentive rates.

IV. g. RSB Battery Pathway

Q. Please summarize the proposed modifications.

A. The Company is proposing to decrease the incentive rate and transition from the five-year incentive lock to the multiyear incentive rate (see discussion in Section IV.f). Under the Company's proposal, participants who enroll in the RSB Battery pathway by June 1, 2024, will receive a $400/kW multiyear incentive rate, participants who enroll in the RSB Battery pathway on or after June 1, 2024, will receive a $225/kW multiyear incentive rate. Any participant who reaches the end of the five-year incentive lock will receive a $200/kW incentive rate.

Q. What is the Company's reasoning for decreasing the incentive rate?

A. The Company is decreasing the incentive rate to bring the cost of procuring a unit of peak demand more in line with the Company's willingness to pay.

Q. In what circumstances would the Company consider increasing the incentive rate in the RSB Battery pathway?

A. The Company would consider increasing the incentive rate in the RSB Battery pathway if it could secure incremental non-customer funding to layer onto the incentive rate.

Q. Is the proposed cutover date of June 1 the same as what the Company presented to the Council on January 25, 2024?

A. No. The Company had presented an earlier cutover date to the Council. Following stakeholder comments about customer acquisition lead times, the Company made the decision to propose a later cutover date that corresponds to roughly six months (the approximate typical upper bound of lead time) following the Company's presentation of its first draft proposal to the Council. Its justification for extending the cutover date is to better comply with the LCP standard of reliability, particularly as it relates to market continuity. An extended cutover date will allow a smoother transition for market participants to the proposed new incentive rate.

Q. Is the proposed incentive rate of $225/kW the same as what the Company presented to the Council?

A. No. The Company had presented a proposed incentive rate of $275/kW at the Council's November meeting and a revised proposed incentive rate of $200/kW at the Council's January meeting. The reasoning behind further decreasing the incentive rate between November and January was to better align with refined values of avoided electric bill cost. Further discussion with stakeholders and analysis following the Council's January meeting made clear that the Company had omitted the value of energy price arbitrage from its value stack. Batteries are able to charge during lower-cost hours and discharge

during higher-cost hours, resulting in lower-cost electricity being supplied even when accounting for round-trip efficiency of the battery. Using spot market price data from ISO-NE for 2021-2023, the Company estimated an approximate value of $13/kW.[13] Accounting for this value brings average avoided electric bill cost to $283/kW across 2024-2026. Subtracting the $53/kW residential administration costs leaves $226/kW for an incentive level. This calculation excludes the financing cost from the RSB unit cost, with the argument that financing may be considered to be a critical driver of equitable participation in the RSB Battery pathway, in alignment with the LCP Standard of prudency. In subsequent program design (post-2026), Rhode Island Energy will reassess the market and the needs of participants, and reserves the right to fold financing cost into the unit cost for the purpose of setting incentive rates.

V. Assessment of Compliance with the LCP Standards

Q. What are the LCP Standards applicable to an electric demand response program as proposed through an SRP Investment Proposal?

A. The LCP Standards applicable to an electric demand response program as proposed through an SRP Investment Proposal are Cost-Effective, Reliable, Prudent,

[13] Rhode Island Energy only includes this value for the RSB Battery pathway because the peak demand reduction from batteries in the Daily Dispatch pathway is negligible relative to total peak demand reduction in the Daily Dispatch pathway at this time.

Environmentally Responsible, and Lower than the Cost of the Best Alternative Utility Reliability Procurement.

V. a. <u>Lower than the Cost of the Best Alternative Utility Reliability Procurement</u>

Q. Please summarize this standard.

A. LCP Standards 1.3.H describes the relevant comparison as

> "the cost of System Reliability Procurement measures, programs, and/or portfolios to the cost of the best alternative Utility Reliability Procurement option using all applicable costs enumerated in the RI Framework. The distribution company shall provide specific costs included in the Cost of System Reliability Procurement. At a minimum, the comparison shall include the applicable cost categories in a Total Resources Cost Test."

Q. Why is the comparison in cost to the best alternative rather than the cost of additional supply, as described by LCP Standard 1.3.G?

A. LCP Standards 1.3.A states, "System Reliability Procurement shall be lower than the cost of the best alternative Utility Reliability Procurement."

Q. In the case of electric demand response, what is the best alternative Utility Reliability Procurement?

A. In the absence of demand response, the best alternative Utility Reliability Procurement is to procure the capacity required to meet peak demand and build the infrastructure required to deliver that peak load.

Q. Does the Company's proposal meet this Standard?

A. Yes, the Company's proposal meets this Standard: the cost of procuring approximately 150 MW of peak demand reduction in 2024-2026 is less than the cost of the best alternative Utility Reliability Procurement.

Q. In accordance with LCP Standards 1.3.H.iii, which costs in the RI Framework were included in the cost of the proposal and which costs are included in the alternative?

A. For the costs of the proposal, the Company included costs of program administration (comprised of staff and vendor costs), costs of incentives budgeted for expected performance, and costs of delivering the HEAT loan (i.e., the cost to buy down the interest rate for HEAT loans budgeted to be used by eligible participants for qualifying demand response technologies).[14]

[14] Please note that the Company excludes the cost to purchase the equipment it uses (if any) for demand response because ConnectedSolutions is predicated on a "bring your own device" program model; any prior investment costs are considered to be sunk for the purposes of this cost comparison.

For the cost of the best alternative, the Company included all categories that appear in some manner on electric utility bills. These include energy and capacity costs, avoided infrastructure costs, and avoided regional network service ("RNS") charges.

In the development of proposed incentive levels, the Company equivalently estimated the value of 1 kW of peak load in terms of avoided costs that would otherwise manifest on electric utility bills and set incentive levels ($/kW) to not exceed that value. This practice compared the proposed program costs as described above to avoided energy cost and associated intrastate energy DRIPE, avoided capacity cost and associated intrastate capacity DRIPE, avoided RNS charge, and avoided transmission and distribution infrastructure costs. The Company then did a hybrid quantitative-qualitative comparison to assess whether the proposed program complies with this LCP standard.

Q. Please elaborate on the Company's findings for the estimated value of 1 kW peak reduction.

A. The Company describes its methods, assumptions, and interim calculation in the Technical Appendix in Schedule 1. The Company estimated the value of 1 kW peak reduction to be $263/kW in 2024 and increasing to $278/kW in 2026. The Company

acknowledges the potential $13/kW incremental value of energy price arbitrage for participating battery technologies.

Q. How does the Company's willingness to pay value compare to the cost of the best alternative Utility Reliability Procurement, as defined in the LCP Standards?

A. The Company's willingness to pay is a proxy for the cost of the best alternative Utility Reliability Procurement as defined in the LCP Standards. The LCP Standards stipulate that the cost of the best alternative Utility Reliability Procurement include "all applicable costs enumerated in the RI Framework" (LCP Standards 1.3.H.i.) and "at a minimum, the comparison shall include the applicable cost categories in a Total Resources Cost Test" (LCP Standards 1.3.H.ii).

Q. If the cost to procure peak demand reduction (i.e., the aggregate cost of procuring each unit of peak demand reduction as proposed within this SRP Investment Proposal) is less than the Company's willingness to pay for that quantity of peak demand reduction, does the Company's proposal meet the standard that the cost of System Reliability Procurement is less than the cost of the best alternative Utility Reliability Procurement?

A. Yes. By definition, the Company's willingness to pay is no greater than the cost of the best alternative utility reliability procurement.

Q. What layers may be able to be added to the value stack in the future?

A. Future program design may be able to consider localized avoided distribution infrastructure cost and incremental energy arbitrage from time-varying rates. The instant proposal does not consider these values because, in the case of the former, the Company does not have the requisite hardware and software or contractual relationship with distributed energy resources to access localized avoided distribution infrastructure value and, in the case of the latter, the Company does not offer time-varying rates at this time.

Q. Is the Company compelled by statute to procure <u>all</u> peak demand reduction that is lower than the cost of the best alternative Utility Reliability Procurement?

A. No. LCP Statute requires "Each electrical and natural gas distribution company shall submit to the commission on or before September 1, 2008, and triennially on or before September 1 thereafter through September 1, 2028, a plan for system reliability and energy efficiency and conservation procurement. In developing the plan, the distribution company may seek the advice of the commissioner and the council. The plan shall include measurable goals and target percentages for each energy resource, pursuant to standards established by the commission, including efficiency, distributed generation, demand response, combined heat and power, and renewables. The plan shall be made public and be posted electronically on the website of the office of energy resources, and shall also be submitted to the general assembly" (R.I. Gen. Laws § 39-1-27.7(d)4).

Nothing in this provision requires that the Company procure all peak demand reduction that is lower than the cost of the best alternative Utility Reliability Procurement, even if that peak demand reduction meets all of the LCP Standards.

Q. Would the Company's proposal change if the parties argued that the cost of the best alternative Utility Reliability Procurement were higher than the Company's willingness to pay?

A. No. With this filing, the Company has put forth a proposal for procurement of peak demand reduction that it considers to be the most appropriate proposal in alignment with the Company's objectives, provision of value for its whole customer base, and in compliance with LCP Standards.

Q. In accordance with LCP Standards 1.3.H.iii, please identify which categories of the RI Framework are not included in either cost estimation and explain why these categories are not included.

A. Table 1, below, references each category from using 2024 values: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4600-WGReport_4-5-17.pdf. Although the Company estimates zero or negligible value for some categories, there are no categories that are not included either quantitatively or qualitatively.

Table 1.

RI Framework Benefit-Cost Category	SRP Investment Proposal Alternative Scenario: Reduce peak demand	Best Alternative Utility Reliability Procurement Baseline Scenario: Serve peak demand	Notes (or explanation of why category is not included)
Power System Level			
Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	-$13/kW (batteries only)	Zero	SRP saves some money from energy price arbitrage relative to URP
Renewable Energy Credit Cost/Value	Zero	Zero	No purchase or selling of RECs within program design; zero value; serving peak demand doesn't change renewable energy cost value
Retail Supplier Risk Premium	Zero	Zero	Estimated as zero/negligible; doesn't affect retail supplier risk premium
Forward Commitment: Capacity Value	-$21/kW	$69/kW	Source: Data from 2021 AESC adjusted for inflation; intrastate capacity DRIPE included

RI Framework Benefit-Cost Category	SRP Investment Proposal Alternative Scenario: Reduce peak demand	Best Alternative Utility Reliability Procurement Baseline Scenario: Serve peak demand	Notes (or explanation of why category is not included)
			as savings in SRP scenario
Forward Commitment: Ancillary Services Value	Negligible/small benefit possible for some participants	Zero	Only applicable to battery participants that also participate in providing ancillary services through ISO-NE
Utility/Third Party Developer Renewable Energy, Efficiency, or DER Costs	$50-450/kW Weighted Average = ~$221/kW	Zero	Cost of running the program (incentive + financing + administration); bring your own device program: costs of equipment assumed to be sunk
Electric Transmission Capacity Costs/Value	Zero	$38/kW	RNS charges for three months (peak season)
Electric transmission infrastructure costs for Site Specific Resources	Zero	$13/kW	Derived from 2021 AESC
Net risk benefits to utility system operations generation,	Zero	Zero	ConnectedSolutions not a new program; proposed

RI Framework Benefit-Cost Category	SRP Investment Proposal Alternative Scenario: Reduce peak demand	Best Alternative Utility Reliability Procurement Baseline Scenario: Serve peak demand	Notes (or explanation of why category is not included)
transmission, distribution from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity			2024-2026 program scale does not create additional utility risks
Option value of individual resources	Possible positive benefit	Zero	Qualitatively assessed; participating ConnectedSolutions resources have shorter commitments/lifetimes than utility infrastructure
Investment under Uncertainty: Real Options Cost/Value	Zero	Zero	Qualitatively assessed above
Energy Demand Reduction Induced Price Effect	Small/negligible benefit	Zero	2021 AESC

RI Framework Benefit-Cost Category	SRP Investment Proposal Alternative Scenario: Reduce peak demand	Best Alternative Utility Reliability Procurement Baseline Scenario: Serve peak demand	Notes (or explanation of why category is not included)
Greenhouse gas compliance costs	Benefit	Zero	Qualitative assessment based on reduced energy (thermostat pathway) and reduced emissions (higher emissions during ISO-NE peak avoided because of shift to lower-emissions off-peak generation)
Criteria air pollutant and other environmental compliance costs	Small/negligible benefit possible	Zero	Qualitative assessment based on logic in row above
Innovation and learning by doing	Positive benefit	Zero	Learning how to build two-way dependent and effective relationship between utility and customers/CSPs
Distribution capacity costs	Zero	$120/kW +/- $40/kW	Internal analysis, avoided T&D workbook, plausible range.
Distribution delivery costs	Zero	Zero	Effectively included in avoided infrastructure costs

RI Framework Benefit-Cost Category	SRP Investment Proposal Alternative Scenario: Reduce peak demand	Best Alternative Utility Reliability Procurement Baseline Scenario: Serve peak demand	Notes (or explanation of why category is not included)
Distribution system safety loss/gain	Zero	Zero	No impact; no risks so no safety loss/gain
Distribution system performance	Zero	Zero	Out of scope for proposed program; requires supplemental investments (e.g., ADMS)
Utility low income	Zero	Zero	LI not called out for targeting (with exception of limitation of HEAT Loan to income-eligible customers)
Distribution system and customer reliability/resilience impacts	Zero	Zero	Out of scope for the proposed program at power system level
Customer Level			
Program participant/prosumer benefits/costs	Positive benefits for participants	Zero	Reduced electric bills, possible backup power for battery participants, possible alternative incentive/revenue streams (e.g., from ISO-NE markets)

RI Framework Benefit-Cost Category	SRP Investment Proposal Alternative Scenario: Reduce peak demand	Best Alternative Utility Reliability Procurement Baseline Scenario: Serve peak demand	Notes (or explanation of why category is not included)
Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Zero	Zero	No other resource savings
Low-Income Participant Benefits	Zero	Zero	None claimed
Consumer Empowerment & Choice	Positive benefit for participants	Zero	Supports third party DER development.
Non-participant (equity) rate and bill impacts	Savings $# from rate and bill impact analysis	Zero	Program designed to lower non-participant bills.
Societal Level			
Greenhouse gas externality costs	Benefit	Zero	Qualitative assessment; benefit from shifting load to lower emissions off peak generation; partially offset by participating fossil-fueled backup generators
Criteria air pollutant and other environmental externality costs	Small/negligible benefit possible	Zero	See above

RI Framework Benefit-Cost Category	SRP Investment Proposal Alternative Scenario: Reduce peak demand	Best Alternative Utility Reliability Procurement Baseline Scenario: Serve peak demand	Notes (or explanation of why category is not included)
Conservation and community benefits	Zero	Zero	No land use impacts anticipated
Non-energy costs/benefits: Economic Development	Benefit	Benefit	Qualitative: bring-your-own means sunk (though acknowledge incentives in purchase decisions); jobs supported through both scenarios; comparison not attempted
Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	Possible benefit	Zero	Qualitative: workforce development; stretch to call ConnectedSolutions RD&D
Societal Low-Income Impacts	Zero	Zero	No LI targeting.
Public Health	Negligible benefit possible	Zero	Qualitative assessment: benefit noted for greenhouse gas and criteria pollutant categories so possible benefit from ancillary impacts not accounted for

RI Framework Benefit-Cost Category	SRP Investment Proposal Alternative Scenario: Reduce peak demand	Best Alternative Utility Reliability Procurement Baseline Scenario: Serve peak demand	Notes (or explanation of why category is not included)
			in those other categories; negligible from small program scale
National Security and US international influence	Zero	Zero	No impact on oil imports.
Total	**$200/kW – (bill savings + energy price arbitrage + qualitative benefits)**	**$240/kW +/- $40/kW**	**Cost of SRP Investment Proposal < Cost of best alternative Utility Reliability Procurement**

1

Q. What does the Company conclude regarding the relative cost of its SRP Investment Proposal compared to the best alternative Utility Reliability Procurement?

A. The Company concludes that the cost of its SRP Investment Proposal is no more than $200/kW (before accounting for resulting electric bill reductions, the value of energy price arbitrage, or qualitatively assessed benefits) while the cost of the best alternative Utility Reliability Procurement is more than $200/kW (with no potential for electric bill reductions or energy price arbitrage and more limited qualitatively assessed benefits).[15] In aggregate terms, the program cost of the Company's proposal is $28.8M ($31.9M total) while the cost of the best alternative Utility Reliability Procurement is estimated at $36M. Therefore, the Company concludes that its proposal is compliant with the LCP Standard lower cost than the best alternative Utility Reliability Procurement.

V. b. Cost-Effective

Q. How did the Company assess whether its proposal is cost-effective?

A. The Company determined its proposal is cost-effective by quantitatively and/or qualitatively assigning value to each category of the RI Framework.

[15] Dividing aggregate three-year program cost ($28,775,911, which is exclusive of regulatory allocation and proposed shareholder incentive) by total planned peak reduction (149,763 kW) yields a three-year average unit cost of $192.14 per kW of peak demand reduction procured. The aggregate three-year cost inclusive of the regulatory allocation and proposed shareholder incentive is $31,873,648, which yields a unit cost of $212.83 per kW.

Q. What is the Company's conclusion?

A. Using the values in Table 1, the Company estimates a cost-benefit ratio of 1.19 in 2024, growing to 1.34 in 2026. Appendix 1 in Schedule 1 contains tables with benefit cost ratios for each track and with and without regulatory allocations or performance incentives. Schedule 2 contains the workpapers associated with these calculations, along with sensitivity analyses with interstate benefits and non-power system benefits includes.

V. c. Reliable

Q. How did the Company assess whether its proposal complies with the LCP Standard of reliability?

A. The Company assessed the following factors in compliance with LCP Standards 1.3.D.i: the ability of the proposal to meet the energy supply or delivery system needs, the ability of previous investments, including identical or similar investments, to support the conclusion that a new investment is reliable, and the potential for implementation issues, including available workforce, market continuity, program scalability. The Company also assessed the following factors in accordance with LCP Standards 1.3.D.ii: the proposal's ability to meet specific identified system needs, the proposal's anticipated reliability as compared to alternatives, operational complexity and flexibility, risks associated with customers' behavior, responsiveness, and ability to potentially modify usage at certain times and seasons.

Q. Is the Company's proposal reliable in terms of the factors from LCP Standards 1.3.D.i?

A. Yes. This proposal is structured to provide tangible value to customers by meeting peak demand needs through lower-cost resources. The Company's prior experience with ConnectedSolutions has allowed the Company to refine the program such that value is highly likely to be realized, and to be realized in a scalable manner. The Company has also assessed the potential for implementation issues, including available workforce, market continuity, and program scalability in designing its proposal. The quantity of peak demand reduction proposed to be procured through each pathway has been carefully considered based on prior participation trends, actual peak demand reduction achieved, and market trends. The Company further adjusted program design based on feedback from stakeholders in the battery market for improving market continuity relative to draft proposals. Finally, the Company is proposing an incentive cap to mitigate risk of overreliance on any one participant's contribution to peak demand response absent appropriate contractual terms and conditions that guarantee performance or recoup lost value from non-performance.

Q. Is the Company's proposal reliable in terms of the factors from LCP Standards 1.3.D.ii?

A. Yes. Specifically, the Company's proposed quantity procured is based on actual peak load reduction rather than contracted peak load reduction and is therefore reasonably likely to be achieved. If, however, less than the quantity proposed by the Company is procured, the Company's proposal is structured on a predominantly unit-basis, so it is reasonably likely to be able to deliver value to customers in a manner that is scalable, flexible, and adaptable. The Company has considered risks associated with participants' responsiveness and mitigated those risks in program design by using actual data in planning (i.e., contracted versus actual peak demand reduction achieved through each pathway).

Q. What does the Company conclude?

A. The Company concludes that its proposal is reliable.

V. d. <u>Prudent</u>

Q. How did the Company assess whether its proposal complies with the LCP Standard of prudency?

A. The Company assessed the following factors in compliance with LCP Standard 1.3.E.i: how the investment supports the goals of the electric system and the purposes of Least-

Cost Procurement, the potential for synergy savings based on alternatives that address multiple needs, how the entire investment proposal affects the risks of ratepayers and the distribution company, how the investment effectively uses available funding sources and integrates with energy programs and policies, and how the investment is equitable in consideration of the allocation of costs, the allocation of benefits, customer access, and customer participation.

Q. What were the Company's findings?

A. The Company's proposal supports the goal of affordability of the electric system by delivering value to all customers in terms of avoided electric bill costs. The Company's proposal supports the goal of reliability of the electric system by mitigating risk of overreliance on any one participant's performance and by encouraging diversified resources (e.g., adding a new pathway and maintaining a technology agnostic approach in the commercial and industrial track). The Company's proposal supports the purpose of Least-Cost Procurement in that it meets electrical energy needs in Rhode Island in a manner that the Company asserts is optimally cost-effective, reliable, prudent, and environmentally responsible.

The Company considered the potential for synergy value based on the value streams that participating resources can provide. As the Company's modernizes its electric grid,

enabling additional value streams, the Company will refine its program design to access those synergy value streams.

The Company considered how the entire investment proposal affects the risks of all ratepayers, from whom programmatic funding is sourced. In its proposal, the Company grows its proposed quantity of low-cost peak demand reduction thereby increasing the likelihood of value for ratepayers. Indeed, the Company designed its program with the express objective of plausibly reducing electric bills for all customers, regardless of participation, relative to a counterfactual in which the Company served all peak demand. The Company further considered risks to ratepayers when setting an incentive cap.

The Company considers its proposal to set the stage for effectively using multiple funding sources and integrating with energy programs and policies. Although the proposed reduction in incentive rates for Daily Dispatch and RSB Battery may be considered as counter to some policy objectives, this proposal begins to disentangle the potential value proposition of batteries in a maturing market. The Company is actively searching for alternative non-customer funding sources to represent stakeholders' willingness to pay for value streams aside from peak demand reduction to layer onto the Company's own willingness to pay through its pre-established (i.e., no startup cost) incentive delivery channel.

Finally, the Company considered how the investment is equitable in consideration of the allocation of costs, the allocation of benefits, customer access, and customer participation. As a direct result of pay-for-performance design, non-participants receive disproportionately lower benefits from ConnectedSolutions because non-participants do not receive performance incentives. In its proposal, the Company purposefully designed the incentive levels and quantity proposed to be procured such that even non-participants are expected to see lower electric bills than the counterfactual. Regarding specific pathways, the Company recognizes the high unit cost of the financing incentive available to participants who choose to finance a battery energy storage system (an estimated value of $843/kW for those participants who receive the financing incentive). The Company's proposal to limit eligibility for this incentive to income-eligible customers both focuses funding for potential participants who need it most and reduces the amount of funding collected from all customers. Although reducing the proposed incentive rate for the RSB Battery pathway is likely to shrink participation growth relative to previous years, doing so is appropriate given the high unit cost of the pathway and the limited number of participants: in the Company's estimation for an incentive rate of $400/kW, funding collected from roughly 1,000 customers would accrue to a single participant. The Company is proposing to make this pathway more equitable by bringing the incentive rate more in line with avoided electric bill costs so that all customers will realize more electric bill savings relative to the counterfactual.

Q. Did the Company conduct any analysis regarding expected bill or rate impacts of its proposal?

A. Yes. The Company's analysis shows that although non-participating residential customers are anticipated to see an increase in annual bill total of $1.76 in 2024,[16] the program design measures put in place will result in annual bill savings of $2.41 by 2026.[17] save $1.95 on their electric bills annually, net of program costs. Non-participating commercial customers are anticipated to save between $34.65 and $93.12 each year. These bill impacts are net of total costs. These benefits are scalable, and benefits for participants will be higher based on incentives earned for performance. Indeed, achieving anticipated electric bill reductions for non-participants was a critical requirement considered throughout the design of the proposed investment. The Company's analysis is contained in Schedule 2.

Q. What is the Company's conclusion?

A. Given the reasoning above, the Company concludes that this proposal is prudent.

[16] The 2024 bill impact is driven by the cost of the RSB Battery pathway, particularly the carryover of $400/kW incentive rates and access to the HEAT loan through June 1, 2024.

[17] The Company estimates a residential non-participant annual bill reduction of $0.08 in 2025.

V. e. Environmentally Responsible

Q. Please summarize the LCP Standard of environmental responsibility.

A. LCP Standards 1.3.F stipulates that the Company shall assess (i) "how investment complies with State environmental and climate policies and shall properly value environmental and climate costs and benefits" and (ii) how the investment affects environmental and climate pollution, where applicable, at a local, regional, and global scale."

Q. What State environmental and climate policies did the Company consider in its assessment.

A. The Company considered the 2021 Act on Climate, the Renewable Energy Standard, and relevant state and federal regulations for backup generators as administered by the Rhode Island Department of Environmental Management.

Q. How did the Company properly value environmental and climate costs and benefits?

A. The Company's benefit-cost assessment used to determine compliance with the LCP Standard of cost-effectiveness integrates assumptions based on the changing emissions of the electric power system (i.e., due to Rhode Island's Renewable Energy Standard) and

contains a qualitative sensitivity analysis for varying values of the social cost of carbon based on alternative plausible assumptions.

Q. Please describe the Company's assessment of how the proposed investment complies with State environmental and climate policies and affects environmental and climate pollution.

A. The Company assessed how the proposed investment complies with State environmental and climate policies and affects environmental and climate pollution via a qualitative comparison between a scenario in which ConnectedSolutions leads to expected peak load reduction and a scenario in which no peak load was reduced. The Company assumed that environmental and climate pollution generated in serving peak load are greater than environmental and climate pollution generated in serving load at times other than peak.[18] The Company asserts that any technology pathway that purely reduces electricity consumption (e.g., foregoing a manufacturing shift) results in lower environmental and climate pollution, all else equal, and therefore meets this standard. Likewise, the Company asserts that any technology pathway that purely shifts load away from peak (e.g., deferring a manufacturing shift) results in lower environmental and climate pollution, all else equal, and therefore meets this standard. Finally, the Company considered technology pathways that shift the service of on-site load from the electric

[18] 2022 ISO New England Electric Generator Air Emissions Report

distribution system to on-site power sources. Two such technologies can do this: battery energy storage and generators. Serving on-site load through battery energy storage systems is likely to result in a reduction in environmental and climate pollution if the battery was charged by a renewable energy resource or by electricity generated outside of peak hours. On the other hand, generators may be powered by fossil fuels, and their environmental and climate pollution may be qualitatively similar to the environmental and climate pollution generated by serving peak load through other means. For this comparison, the Company defers to the statutory authority of Rhode Island Department of Environmental Management ("DEM") in administering regulations associated with environmental and climate pollution. DEM is also subject to the 2021 Act on Climate. By aligning eligibility requirements for generators participating in ConnectedSolutions with DEM's provision of permit(s) for back-up generators, the proposal complies with State environmental and air pollution control policies.

Q. Will the Company's proposed reduction in incentive levels for battery participants prevent Rhode Island from meeting its 100% Renewable Energy Standard by 2033?

A. No, the Company's proposed reduction in incentive levels for battery participants will not prevent Rhode Island from meeting its 100% Renewable Energy Standard by 2033. Although the proposed incentive levels are likely to result in slower battery deployment and lower resulting battery penetration relative to a counterfactual with higher incentive

levels, the Rhode Island Public Utilities Commission finds that batteries are not critical to meeting the State's 100% Renewable Energy Standard.[19] Furthermore, the Company's proposal is for years 2024-2026, and does not contemplate future incentive levels, accessible value streams, or other potential revenues for batteries outside of ConnectedSolutions or post-2026.

Q. Will the Company's proposed reduction in incentive levels for battery participants prevent Rhode Island from meeting its 2030 greenhouse gas emissions reduction mandate set forth in the 2021 Act on Climate?

A. No, the Company's proposed reduction in incentive levels for battery participants will not prevent Rhode Island from meeting its 2030 mandate. The 2021 Act on Climate mandates a statewide, economy-wide greenhouse gas emissions reduction of 45 percent below 1990 levels by 2030. Even if this mandate were to be hypothetically specifically applied to the electric sector (this is not contemplated in the statute), emissions from the electric sector are primarily governed by compliance with the 100% Renewable Energy Standard. The Commission's analysis shows that batteries are not critical to meeting the Renewable Energy Standard through 2030.[20]

[19] See Chapter 4.2: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-10/RIPUC%20Final%20Storage%20Report_Docket%205000.pdf

[20] Ibid.

Q. Will anything about the Company's proposal accelerate or increase the State's ability to meet its 2030 greenhouse gas emissions mandate?

A. Yes, the Company's proposed increase in enrollment incentive for the thermostat pathways and addition of an EVDR pathway will both support the State in achieving its 2030 mandate. First, higher enrollment incentives will encourage more participation in the thermostat pathway, which will result in energy savings and therefore lower emissions. Second, providing incentives to EVDR participants may encourage EV owners to share their experiences with new EV and non-EV owners alike which can prompt new enrollees, encourage voluntary load shifting, and potential participation in additional ConnectedSolutions pathways. Finally, the intentional program design to avoid electric bill costs will aid in price signals that encourage electrification (and resulting decarbonization as we approach 100% Renewable Energy Standard).

Q. Generally, please discuss the interactions between the proposed program, electric rates, and decarbonization.

A. By designing the program to reduce electric utility bills, we are putting downward pressure on electric rates and supporting a price signal that will encourage electrification relative to the counterfactual. In hypothetical counterfactual A, where there is no demand response program, customers have to pay more to serve peak demand, so electric rates and bills would be higher and therefore discourage electrification. In hypothetical

counterfactual B, where we increase unit cost of peak demand and/or buy higher quantity of higher cost peak demand reduction, customers see less bill decrease or even bill increase, which also discourages electrification. Electrification is one validated pathway to decarbonization, so discouraging electrification discourages decarbonization. The Company asserts its proposed program strikes the best balance in encouraging decarbonization through resulting price signals.

Q. What is the Company's conclusion?

A. Given the reasoning above, the Company considers its proposal to be environmentally responsible.

VI. Cost, Funding Sources, and Cost Recovery

Q. What is the cost of the Company's proposal?

A. The Company is proposing a three-year program with an aggregate cost of $31,870,927. The costs in 2024, 2025, and 2026 are $9,809,938, $10,450,896, and $11,610,093, respectively.

Q. What is the Company's proposed funding plan?

A. The Company proposes to fund ConnectedSolutions and recover costs through the SRP Factor which will be included within the total EE Charge on electric customer bills. In

2024, the Company proposes an SRP Factor of $0.00224/kWh to be collected from June 1, 2024, through December 31, 2024. For 2025, the Company will propose an SRP Factor (to be reconciled with actual expenditures relative to budget, peak demand reduction relative to planned, and calculated with updated sales forecast) from January 1, 2025, through December 31, 2025. In addition, for 2026, the Company will propose an SRP Factor (to be reconciled with actual expenditures relative to budget, peak demand reduction relative to planned, and calculated with updated sales forecast) from January 1, 2026, through December 31, 2026. The Company proposes to reconcile for the 2026 calendar year beginning January 1, 2027.

Q. Please summarize the Company's proposal for a performance incentive mechanism.

A. The Company is proposing to share value created through ConnectedSolutions between customers and shareholders, with 80 percent of value being retained by customers in the form of avoided electric bill costs and 20 percent of value be retained by the Company. 100 percent of incentive value will be retained by participants, and 100 percent of value associate with value streams not realized through avoided electric bill costs will be retained by society.

Q. How did the Company forecast the amount of value to be shared?

A. The following equation describes this calculation to determine value to be shared each year. For each pathway, the Company subtracted the unit cost (*P*) of procuring a unit (kW) of peak demand reduction from the relevant estimate of avoided electric bill cost (*AEBC*), with the difference multiplied by the number of units (*Q*) proposed to be procured through that pathway. Value to be shared is the sum across all pathways.[21]

$$Value = \sum_{pathway} \left(\left(AEBC_{pathway} - P_{pathway} \right) * Q_{pathway} \right)$$

Q. How does the Company propose to reconcile the planned shareholder incentive with actual peak demand reduction?

A. The Company will calculate the actual amount of peak demand reduction (*kW*) times the pre-set avoided electric bill cost (*AEBC*) of a unit of demand reduction for that pathway, summed across all pathways, less actual costs:

[21] This aligns with the conceptual methodology to determine the performance incentive mechanism as proposed in Docket No. 23-47-EE: "Rhode Island Energy proposes a dollar per megawatt peak reduction performance incentive for its demand response achievements. The level of incremental incentive is tied to quantitative net benefits, as described below. The objective is to share quantifiable cash savings with customers."

$$Shareholder\ Incentive = 0.20 * \left[\left[\sum_{pathway} \left(kW_{pathway} * AEBC_{pathway}\right)\right] - Actual\ Program\ Costs - Regulatory\ Allocation\right]$$

The Company proposes to use the following values for avoided electric bill cost in 2024-2026:

Pathway (all values in $/kW)	**2024**	**2025**	**2026**
BYOT	$263.47	$270.97	$278.32
EVDR	$262.80	$270.32	$277.61
RSB Battery	$275.53	$283.22	$290.69
TD	$262.80	$270.32	$277.61
DD[22]	$262.80	$270.32	$277.61

Q. Does the Company propose to include avoided electric bill costs for peak demand reduction through the voluntary pathway?

A. No. The Company does not propose to estimate or measure peak demand reduction due to customers' voluntary participation in the voluntary pathway.

[22] The Company does not propose to use the AEBC specific to batteries for Targeted or Daily Dispatch because there are currently no batteries participating in either pathway to the Company's knowledge. In the event batteries are added, the incremental value of energy price arbitrage will accrue 100 percent to customers through 2026. The Company will reassess its proposed performance incentive mechanism, and the way in which it accounts for energy price arbitrage and other value streams, in future SRP Investment Proposals.

Q. What is the dollar amount the Company proposes to earn as a performance incentive?

A. If the planned peak demand reduction of ConnectedSolutions is realized, the Company would earn $472.0 thousand in 2024, $760.8 thousand in 2025 and $998.9 thousand in 2026.

Q. Is the dollar amount that the Company proposes to earn as a performance incentive included in the proposed SRP factor?

A. Yes, the SRP Factor includes the proposed performance incentive. The Company proposes to reconcile each year's performance incentive based on actual performance, with the reconciliation affecting the subsequent year's SRP Factor.

Q. How does the Company intend to use the shareholder incentive?

A. The Company intends to earmark this shareholder incentive for further reinvestment into the electric distribution system. Such investment may support grid modernization, asset condition work, or other work, all with the intent of improving the safety and reliability of the electric distribution system in Rhode Island. Such reinvestment will occur through appropriate regulatory channels and corresponding ratemaking.

Q. Is the Company's proposed performance incentive mechanism consistent with the PIM principles?

A. Yes, the Company's proposed performance incentive mechanism is consistent with the PIM principles identified in Docket No. 4943.

Principle 1 states, "A performance incentive mechanism can be considered when the utility lacks an incentive (or has a disincentive) to better align utility performance with the public interest and there is evidence of underperformance or evidence that improved performance will deliver incremental benefits." In the scenario where the Company serves peak demand, the Company earns a return on the infrastructure built to deliver that level of peak demand. In the scenario where the Company reduces peak demand through ConnectedSolutions, the Company foregoes its return on investment because there is less infrastructure needed. Therefore, the Company has a natural disincentive and an incentive is warranted, pending alignment with the following four principles.

Principle 2 states, "Incentives should be designed to enable a comparison of the cost of achieving the target to the potential quantifiable and cash benefits." The proposed performance incentive mechanism is driven solely by a comparison of the cost of reducing peak demand to the quantifiable cash benefits of avoided electric bill cost. Therefore, the performance incentive is fully aligned with this principle.

Principle 3 states, "Incentives should be designed to maximize customers' share of total quantifiable, verifiable net benefits. Consideration will be given to the inherent risks and fairness of allocation of both cash and non-cash system, customer, and societal benefits." The design of the proposed performance incentive mechanism is scalable, such that more peak demand reduction leads to more value for customers. The Company proposes to reconcile the performance incentive on an annual basis based on actual peak demand reduction. Furthermore, 100 percent of the non-quantifiable, non-cash, participant, and societal benefits accrue to customers. Therefore, the proposed performance incentive mechanism is designed to maximize customers' share of total quantifiable, verifiable net benefits.

Principle 4 states, "An incentive should offer the utility no more than necessary to align utility performance with the public interest." The counterfactual in which peak load is served would result in a return on infrastructure investment. For the purposes of program design planning, the Company estimates that 1 kW of peak demand avoids about $120 of distribution infrastructure cost. The Company's allowed rate of return, 9.275 percent, would net about $10-11/kW in earnings. In the state of the world where the Company instead reduces peak demand, the average value to be shared between the Company and customers is about $73/kW. The Company proposes twenty percent, about $14-15/kW, be shared with the Company. The Company may earn more if it is able to reduce the unit

cost of procuring peak demand reduction but would earn less if the costs of peak demand reduction were to grow, all else equal. Therefore, the proposed performance incentive mechanism is sufficient, but no more than necessary, to prompt the Company to pursue and grow ConnectedSolutions while maintaining strong cost control for customers.

Principle 5 states, "The utility should be offered the same incentive for the same benefit. Stated another way, no action should be rewarded more than an alternative action that produces the same benefit." The Company has no other incentive available to it for peak demand reduction; therefore, the proposed performance incentive mechanism is aligned with this principle.

VII. Conclusion

Q. Does this conclude your testimony?

A. Yes, it does.

The Narragansett Electric Company
d/b/a Rhode Island Energy

System Reliability Procurement Investment Proposal for Electric Demand Response 2024-2026

February 8, 2024

Docket No. 24-06-EE

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™
a PPL company

Contents

Section 1. Introduction

In accordance with Least-Cost Procurement ("LCP") Statute and LCP Standards, Rhode Island Energy respectfully files this proposal for continuation of its electric demand response program, branded ConnectedSolutions, during 2024-2026. Herein, the Company describes electric demand response within the stepwise system reliability procurement process, discusses the objectives that underpin the design of ConnectedSolutions, proposes and motivates some program design modifications, sets an annual peak demand reduction procurement schedule with associated budget, and requests approval for cost recovery of the budget via the System Reliability Procurement ("SRP") Factor added to the Energy Efficiency System Benefit Charge (EE Charge).

Timeline for Development and Review

September 6	Preliminary draft SRP Investment Proposal circulated for external review and feedback
September 20	Opportunity for discussion of SRP Investment Proposal at the SRP Technical Working Group meeting
September 21	Revised draft SRP Investment Proposal included in final draft of *2024-2026 SRP Three-Year Plan*; opportunity for discussion at the Rhode Island Energy Efficiency and Resource Management Council ("Council") meeting on September 28
October 18	Opportunity for discussion of SRP Investment Proposal at the SRP Technical Working Group meeting
November 9	Draft SRP Investment Proposal submitted to the Rhode Island Division of Public Utilities and Carries ("Division") and Council for review per LCP Standards 6.3.G
November 15	Discussion at the SRP Technical Working Group meeting
November 16	Discussion at the Council meeting
November 17	SRP Investment Proposal included as Appendix to *2024-2026 SRP Three-Year Plan* filed with the Rhode Island Public Utilities Commission ("Commission")
January 10	Discussion of technical method and valuation of avoided electric bill costs with the SRP Technical Working Group
January 19	Revised SRP Investment Proposal submitted to the Council as meeting materials
January 25	Discussion at the Council meeting
February 6	SRP Investment Proposal filed with the Commission

Section 2. Electric System Needs and Optimization

Reducing Supply Costs through Electric Demand Response

System Need or Optimization

Electricity supply costs are partially driven by the high cost of electricity during the few hours of the year when we use the most electricity. During these "peak periods," the most expensive generators are needed to supply enough electricity to meet demand, and their cost is factored into the supply rates customers incur. Electric infrastructure also must be sized to deliver this level of electricity to meet peak demand.

Although Rhode Island Energy is an electricity delivery company (akin to FedEx or UPS for delivering packages), we are obliged to help customers who choose not to buy supply from a third-party supplier by buying electricity in bulk via supply contracts chosen in auctions and through the wholesale market. Rhode Island Energy cares about helping customers access the most affordable electricity and, as such, has identified an opportunity to reduce supply costs by incentivizing demand reductions during peak periods. Reducing peak supply needed also has the corollary benefits of avoiding further investments in the electric system infrastructure.

System Reliability Procurement – Electric System Screening Criteria

This optimization meets all four electric system screening criteria and is, therefore, an opportunity for system reliability procurement:

1. The optimization is not related to an asset condition issue;
2. The optimization is eligible because the optimization requires load relief;
3. The opportunity for system reliability procurement is likely to garner sufficient market interest; and
4. There is adequate time to implement a system reliability procurement solution.

Best Alternative Utility Reliability Procurement Solution

Demand response proposed for this system need is specifically to reduce system-level peak demand. In the absence of demand response, the best alternative Utility Reliability Procurement is to procure the capacity required to meet peak demand and build the infrastructure required to deliver that peak load.

Solicit and Evaluate System Reliability Procurement Proposals

This system reliability procurement opportunity has been accessed since 2019 through the Company's demand response program, branded ConnectedSolutions.[1] As of September 2023, approximately 8,000 customers have participated in ConnectedSolutions through their connected thermostats, battery energy storage systems, and production process curtailments. In aggregate, the participation of these customers has led to a meaningful reduction in peak load. Rhode Island Energy submits this SRP Investment Proposal to procure peak demand reduction in 2024 through 2026 through a pay-for-performance program with a "bring your own device" program model.

Request Regulatory Approval

This SRP Investment Proposal is submitted in compliance with Chapter 5 of the LCP Standards.

Implement Solution

Pending regulatory approval, Rhode Island Energy will reopen ConnectedSolutions for the 2024 peak demand season on June 1, 2024. Rhode Island Energy will report the resulting impacts in its *SRP Annual Report*.

[1] ConnectedSolutions had previously been housed within filings related to energy efficiency (e.g., *2021-2023 Energy Efficiency Three-Year Plan*, *2023 Energy Efficiency Annual Plan*). Beginning in 2024, Rhode Island Energy will include ConnectedSolutions within filings related to system reliability procurement instead.

Section 3. Motivation, Objectives, and Program Design Principles

Electricity supply costs differ in the summer and the winter, driven by economics of generation plants needed to serve the amount of electricity consumed by customers (called "load") and the fuel costs for those generation plants. On hot, humid summer weekday afternoons and evenings, customers typically demand the most electricity, and this "peak demand" requires relatively less economically efficient generators to produce electricity to serve the load. These "peaker plants" are the most expensive generators and drive-up summer electricity supply costs.[2] Furthermore, electric transmission and distribution infrastructure must be sized appropriately to serve peak demand.

Based on the relative cost savings identified, Rhode Island Energy proposes to procure peak demand reduction through a program-based procurement process in 2024-2026. By procuring peak demand reduction rather than serving peak demand, we estimate avoided energy and capacity costs, associated demand reduction induced price effects (DRIPE), some level of energy price arbitrage, avoided regional network service ("RNS") charges, and avoided infrastructure costs, all of which will lead to lower electric bills for customers in addition to non-electric bill value that may be accrued by participants and society.

The objective of Rhode Island Energy's demand response program, branded ConnectedSolutions, is to reduce regional coincident peak demand.

In offering ConnectedSolutions, the Company asserts the following program design principles, explained further below:

1. Be agnostic toward technology and participants
2. Encourage diffuse and diverse participation for reliable response
3. Right-size incentives
4. Comply with LCP Standards
5. Facilitate easy participation
6. Share value created

Stemming from the program objective to reduce regional coincident peak demand, Rhode Island Energy does not differentiate a kilowatt reduced by one technology or participant from a kilowatt reduced by another technology or participant. Each of those kilowatts reduced has the same value for putting downward pressure on electricity costs.[3] In this manner, ConnectedSolutions is technology and participant agnostic.

[2] Electricity supply costs reflect three components: energy, capacity, and ancillary. Reducing peak demand puts downward pressure on energy and capacity supply cost components, which benefits all customers.

[3] In our modeling, Rhode Island Energy includes the value of energy price arbitrage for battery energy storage systems and the value of energy savings and associated DRIPE for thermostats.

This principle is most clearly displayed in commercial and industrial participation in ConnectedSolutions, where participants can use any technology, process, or other innovation to reduce peak demand. For residential and small business participants, technology is limited by practical considerations for implementation (i.e., a subset of thermostat and battery manufacturers and models). Rhode Island Energy seeks to expand eligible technologies in 2024-2026 to include electric vehicles that can automatically curtail charging during peak events.

ConnectedSolutions is a voluntary program; not all participants reduce demand when called on, nor are they required to. Rhode Island Energy seeks to build a demand response program with a relatively certain level of response from its participants. This leads to favoring program design that encourages diffuse participation (i.e., no one participant's level of response substantially sways the overall peak demand reduction achieved by the program) and diverse participation (i.e., no one technology type exerts a disproportionate influence on the overall peak demand reduction achieved by the program). This principle is intended to be complementary – not contradictory – to the principle of being technology and participant agnostic. All else equal, more participants and more technologies will result in a more reliable and consistent level of actual average peak demand reduction. Rhode Island Energy seeks to encourage more participants over fewer, with more technology types than fewer, within its program design for ConnectedSolutions.

While the value of each kilowatt of peak demand reduction is roughly equivalent, achieving each kilowatt of peak demand reduction may require different levels of action or opportunity cost on the part of the participant. For example, an automatic setback to a participant's thermostat requires no action, while a request for participants to reduce their thermostats manually requires some action. Another example: having a thermostat that is controllable is a relatively small upfront cost and workload when compared to the upfront costs and work entailed to install a battery energy storage system. A third example for good measure: the opportunity cost of setting back a thermostat (potential temporary discomfort) is small relative to the opportunity cost of skipping a production sequence (definite unrecoverable lost revenue). Rhode Island Energy's third program design principle posits that incentives should be right sized to spur action; because different methods of reducing peak load require different burdens, it makes sense to differentiate incentive levels. Doing so will minimize program costs while achieving the same peak demand reduction.

Demand response activities are contemplated within the Least-Cost Procurement Statute, and further stipulated in the Least-Cost Procurement Standards. Accordingly, demand response must be reliable, prudent, cost-effective, and environmentally responsible. These Standards constitute guardrails on program design. One example of the application of these guardrails is consideration of market continuity and disruption to the market that may arise from program design changes. Another example: we propose to adhere to the standard of environmental responsibility by requiring that any participating fossil-based generation have the requisite environmental compliance permits from the Rhode Island Department of Environmental Management.

Of course, customers only receive benefits of ConnectedSolutions if there are program participants, so Rhode Island Energy is proposing to clarify how customers in different rate classes can participate in ConnectedSolutions. The intent is to clarify how and when participants may stack incentive payments.

Finally, Rhode Island Energy is creating value by offering ConnectedSolutions; indeed, creating value is a cornerstone of program design. Rhode Island Energy is careful to procure peak demand reduction through ConnectedSolutions such that customers benefit through reduced utility bills *regardless of their participation in the program*. Of course, customers who participate will also receive incremental value through incentive payments. In considering tangible monetary value – customers keep money in their wallets because electricity bills are less expensive with ConnectedSolutions relative to the counterfactual of serving peak load – Rhode Island Energy seeks to share this quantifiable monetary value between customers and its shareholders such that *all* parties are better off with ConnectedSolutions than without.

Section 4. Program Design for 2024-2026

This section describes major program design elements of ConnectedSolutions and highlights proposed program design modifications for 2024-2026. This section is not intended to be comprehensive of all program design detail; such detail is developed and made available in advance of each peak demand season, annually.

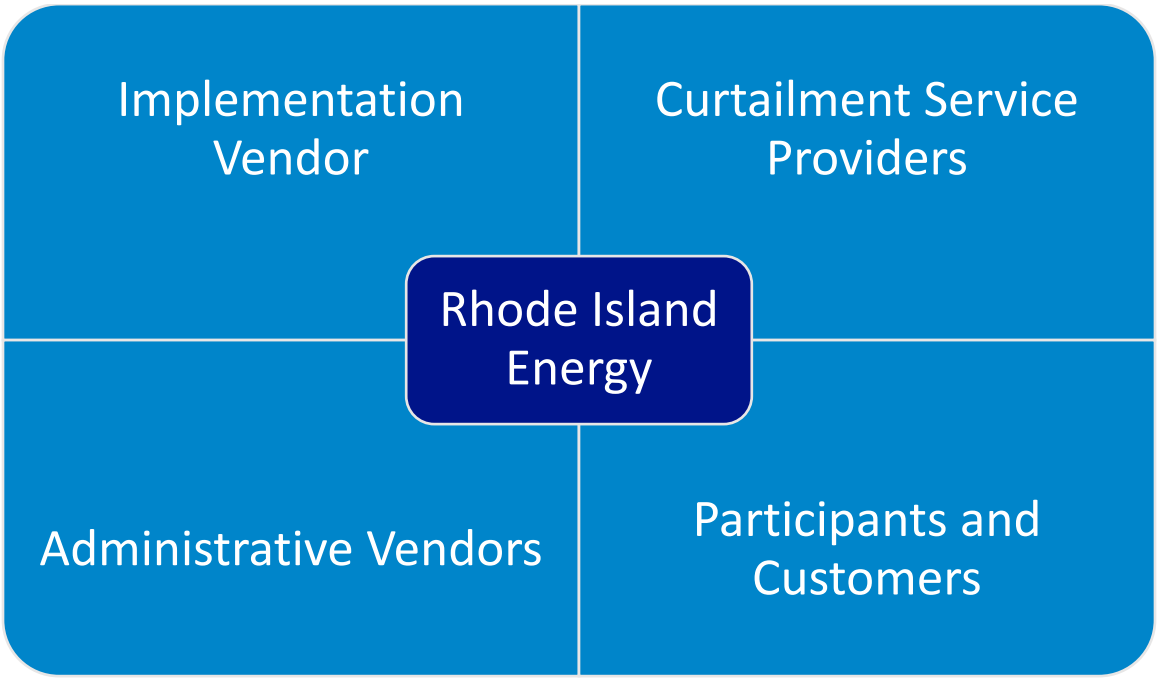
Administration

Rhode Island Energy's Role:

Rhode Island Energy serves as the Program Administrator, providing strategic direction and management of ConnectedSolutions. Rhode Island Energy determines its proposed annual procurement schedule of peak demand reduction and administers the program through which that peak demand reduction is procured. Rhode Island Energy is uniquely suited for this role because of its expertise in wholesale energy and capacity markets, knowledge of its electric distribution system, everyday relationship with its customers to promote program participation, relationships that enable coordination with other electric distribution companies regionally, and ability to coordinate demand response with all other business activities.

Implementation Vendor:

Rhode Island Energy contracts with a third-party solution provider that offers software-as-a-service to implement day-to-day program operations. This implementation vendor is responsible for managing relationships and contracts with technology providers, in order to enable those technologies to participate in ConnectedSolutions (or, more precisely, to enable customers who have those particular technology types and models to enroll and participate). The implementation vendor also assists with data collection, participant enrollment, program impact evaluation, participant satisfaction, troubleshooting, incentive payouts, and ancillary technical assistance. Contracting with a vendor for these roles allows Rhode Island Energy and its customers to benefit from the innovation and price competition within the competitive market for demand response implementation.



Curtailment Service Providers:

Rhode Island Energy and its implementation vendor work with a network of curtailment service providers. These curtailment service providers manage relationships with commercial and industrial customers under their own, independent contracts for value-sharing to which Rhode Island Energy is not party. However, curtailment service providers are essential to the ecosystem of ConnectedSolutions so that they align their support for commercial and industrial customers with Rhode Island Energy's calls for peak demand reduction.

Administrative Vendors:

Rhode Island Energy contracts with additional vendors to support administrative functions, including but not limited to, administering financing interest buy-down incentives.

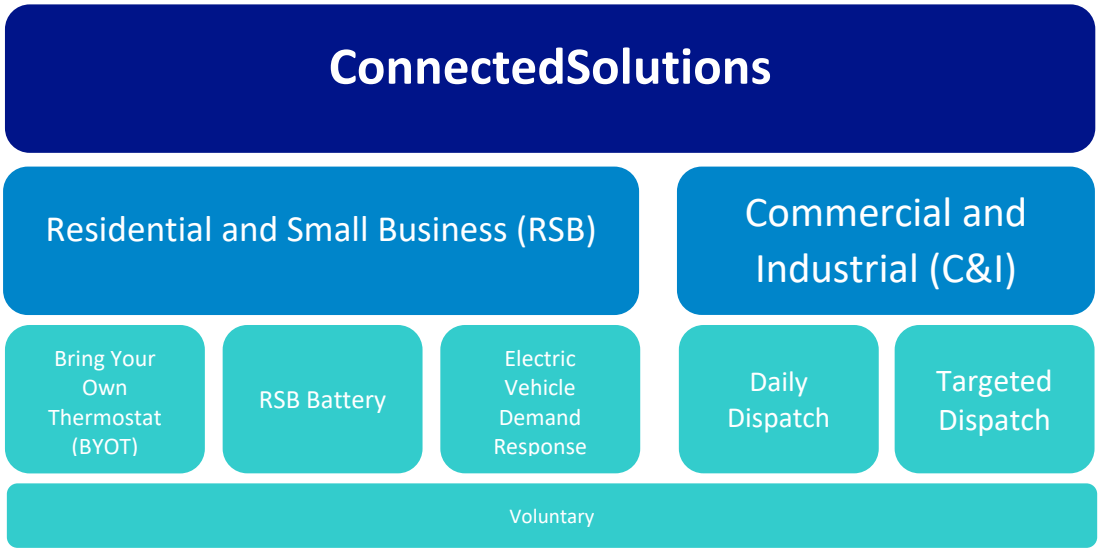
Participants and Customers:

Rhode Island Energy designs ConnectedSolutions such that all customers benefit regardless of participation; however, these benefits only materialize if a subset of customers participate in the program. A participant not only receives the value that accrues to all customers regardless of participation, but also receives an incentive payment for their participation and/or performance.

ConnectedSolutions

The program structure of ConnectedSolutions is illustrated in Figure 1, below. ConnectedSolutions as a whole is referred to as a "program." ConnectedSolutions has two "tracks" through which customers may participate: Residential and Small Business ("RSB") and Commercial and Industrial ("C&I"). Each of these tracks contains multiple "pathways" for participations. Participants in the RSB track can participate via the Bring Your Own Thermostat ("BYOT") pathway, the RSB Battery pathway, and/or the Electric Vehicle Demand Response ("EVDR") pathway. Participants in the C&I track can participate in the Daily Dispatch pathway and/or the Targeted Dispatch pathway. All customers – residential, small business, commercial, and industrial customers – can participate in the Voluntary pathway.

Figure 1



Notes: ConnectedSolutions is a 'program' (shown in navy) with two 'tracks,' the Residential and Small Business track and the Commercial and Industrial track (shown in blue). Each track has a number of 'pathways' through which to participate (shown in teal).

Stakeholders have noted the importance of expected cash flows in financial planning and procurement decisions for some demand response investments, like battery energy storage systems. In prior program years, the Company had advertised a "five-year rate lock" whereby participants could expect to receive the same incentive levels as their first year of enrollment in years two through five. Although the Company intended and continues to intend to honor five years of consistent incentive rates, the Company obtained funding for ConnectedSolutions on a more frequent annual basis. The term "five-year rate lock" obscured this annual proposal and approval process, which introduced risk into the market for years beyond the annual regulatory approved year. Beginning in 2024, the Company is attempting to provide more clarity and transparency with transitioning to the term "multiyear incentive rate." By removing the work "lock," the Company intends to make it clearer that incentive levels offered past the current proposal are subject to change. The Company proposes its incentive rates to be the same for five years from the first year of participation for new participants in ConnectedSolutions, subject to and in compliance with the normal proposal and oversight process and LCP Standards. Although the Company intends to maintain incentive levels for five years from the year of enrollment in the multiyear incentive rate paradigm, the Company explicitly reserves the right to amend incentive levels if warranted. To offset potential perceived reduction in certainty from potential participants, the Company is extending the duration for which it is proposing and requesting approval for ConnectedSolutions (proposing for three years instead of one year). The Company is proposing to honor the "five-year rate lock" for participants for five years following enrollment. Additional detail for affected pathways is provided below.

Residential and Small Business ("RSB") Track

To participate in the RSB track, customers must be in rate classes A-16, A-60, or C-06; customers in other rates classes are ineligible to participate in the RSB track.[4] Participants in the RSB track may stack incentives through setting back thermostats, discharging battery energy storage systems, curtailing electric vehicle charging, or voluntarily pre-loading or deferring electricity consumption. Incentive structures, levels, and eligibility requirements are discussed further below.

[4] Customers in the C-06 rate class will be provided the flexibility to choose to participate in either the Residential track or the Commercial track at the beginning of each season. They may not participate in both tracks at the same time or switch to a different track midseason.

Bring Your Own Thermostat ("BYOT")

Residential and small business customers may enroll eligible devices in the BYOT pathway. During peak periods, connected thermostats will automatically increase target cooling levels, thereby reducing demand of central air conditioning units or central heat pumps. Eligibility is defined by thermostat manufacturers and model, as determined by the implementation vendor.

Incentive structure and amount:

Eligible participants receive a one-time enrollment incentive of $50 per enrolled device followed by an annual participation incentive of $20 per device per year, to be rendered at the end of the peak season for all participants.

Proposed Changes for Bring Your Own Thermostats Pathway

Rhode Island Energy proposes to increase the upfront enrollment incentive from $25 to $50 to encourage higher participation rates. Our goal is adding 4,000 new participants each year!

Residential and Small Business ("RSB") Battery

During peak periods, battery energy storage systems discharge electricity to serve on-site load and export electricity to the electric distribution system for neighboring customers to use, thereby reducing peak demand.

Eligibility

Residential and small business customers may enroll. Batteries that participate must be from eligible manufacturers (as specified in program documentation). Incentive payments will be capped at $6,875 per year, which represents an incentive for a battery that reduces regional coincident peak load by 25 kW per peak event on average.

Incentive structure and amount:

Newly eligible participants receive an annual performance incentive of $225 per average peak kilowatt reduced per peak event per year, to be rendered at the end of the peak season for all participants. It is Rhode Island Energy's intention to offer this multiyear incentive rate for the first five years for new participants, however incentive levels after 2026 are subject to review and approval.

Participants who complete their initial five years of participation during 2024-2026 will transition to an annual performance incentive of $200 per average peak kilowatt reduced per peak event per year, to be rendered at the end of the peak season.

Low-income eligible participants may additionally opt to leverage the HEAT Loan to support financing their battery energy storage systems. The HEAT Loan provides low-interest rate financing, with zero-percent interest financing available to some customers based on income eligibility.

Changes for the RSB Battery Pathway

In accordance with the program design principle to right-size incentive levels, Rhode Island Energy is proposing to change the amount of the performance incentive. Under prior program design, participants received $400 per average kilowatt reduced per peak event per year. The new incentive will allow new participants to receive $225 per average kilowatt reduced per peak event per year. Rhode Island Energy seeks to right-size the performance incentive to generate value in terms of reduced customer electric bills.

Rhode Island Energy also proposes to limit eligibility for the HEAT loan for purposes of financing a demand response-enrolled battery energy storage system to income-eligible customers. This program design modification substantially reduces the cost to procure peak demand reduction through battery energy storage dispatch, thereby growing value in terms of reduced customer electric bills.

Incentive payout schedule

Table 1, below, shows the eligible incentive rate for battery energy storage dispatch based on year of peak season program participation. This table includes the proposed honoring of the five-year rate lock and to uphold a multi-year incentive rate for five years for any new participants, however incentive levels are subject to review and approval post-2026. To qualify for the $400 incentive rate, participant(s) must successfully enroll with a newly installed battery on or before May 31, 2024.

Table 1. Battery energy storage dispatch incentive schedule

Customer enrolled with a newly installed battery and begun peak season participation….	2020	2021	2022	2023	2024	2025	2026	2027*	2028*
2019	$400	$400	$400	$400	$200	$200	$200	TBD	TBD
2020	$400	$400	$400	$400	$400	$200	$200	TBD	TBD
2021	-	$400	$400	$400	$400	$400	$200	TBD	TBD
2022	-	-	$400	$400	$400	$400	$400	TBD	TBD
2023	-	-	-	$400	$400	$400	$400	$400	TBD
2024 (Participants enrolled on or before May 31, 2024)	-	-	-	-	$400	$400	$400	$400	$400
2024-2026 (Participants enrolled on or after June 1, 2024)					$225	$225	$225	$225	$225

Notes: Each row represents the peak season in which a customer first enrolled with a newly installed battery and began peak season participation. Each column represents the year of the peak season. The contents of the cells indicate the eligible incentive level in dollars per average kW reduced per peak event across that year's season. For example, a customer who enrolled with a newly installed battery and begun peak season participation in 2019 had been eligible to receive $400/kW for average kW reduced in years 2020 through 2023, and $200/kW in years 2024-2026. If a customer's enrollment commences mid-season, that system will receive 0 kW as performance for any events missed but will be allowed to earn performance on any remaining events of that season. Note that for all customers, incentives will be set in three-year periods "2024-2026". *During the next three-year review, the incentives may be re-evaluated and adjusted based on market conditions for the Program Period 2027-2029. All incentives are subject to review and oversight.

Electric Vehicle Demand Response ("EVDR")

New for 2024-2025, Rhode Island Energy proposes to incentivize participants who drive electric vehicles to curtail charging during peak demand periods.

Incentive structure and amount:

Eligible participants receive a one-time enrollment incentive of $50 per enrolled vehicle followed by an annual participation incentive of $20, to be rendered at the end of the peak season for all participants.

Notes about program design:

Rhode Island Energy may propose an off-peak charging rebate program for future years. The electric vehicle charging response option through ConnectedSolutions is distinct and separate from a potential off-peak charging rebate program in the following ways:

- The off-peak charging rebate program structures its incentive as a dollar value per *kilowatt-hour* reduced *cumulatively* during peak periods; the incentive for electric vehicle charging response through ConnectedSolutions is structured as a dollar value per *participation*.
- The off-peak charging rebate program requires an action by the participant to participate in each peak period; the electric vehicle charging curtailment option through ConnectedSolutions does not require any action by the participant to participate.
- Customers may only participate in one program or the other; customers may not participate in *both* off-peak charging rebate *and* electric vehicle charging response through ConnectedSolutions.

By offering both the off-peak charging rebate program and the electric vehicle charging curtailment option through ConnectedSolutions, Rhode Island Energy seeks to learn about the differential impacts and customer acceptance of these programs to reduce peak demand. Such learnings may inform future program and rate designs.

New Pathway!

This is a new pathway that has not been available to customers in prior years.

Prominent market signals include state incentives for electric vehicles through its DRIVE program, federal tax incentives for electric vehicles through the Inflation Reduction Act, and federal support for electric vehicle charging infrastructure through National Electric Vehicle Infrastructure (NEVI) funding. These market signals are consistent with state policy that encourages electric vehicles (e.g., the 2022 Update to the 2016 Greenhouse Gas Emissions Reduction Plan, Advanced Clean Cars II Standards that phase out sales of new internal combustion engine vehicles).

Rhode Island Energy seeks to encourage off-peak charging behavior as Rhode Islanders transition to electric vehicles. This pathway is expected to be a low-cost pathway to reduce peak demand.

Voluntary

Rhode Island Energy proposes a new communications strategy to encourage voluntary peak reduction through any means or technology by any customer in response to peak events.

Incentive structure and amount:

Voluntary demand response will not provide any direct monetary incentive to participants for peak demand reduction, although all customers will benefit through downward pressure on electricity costs.

Notes about program design:

Rhode Island Energy will communicate about voluntary calls for demand response using its social media channels and via a banner on its webpage. Rhode Island Energy anticipates posting 2-3 calls for voluntary demand response during the peakiest peaks each year. Rhode Island Energy recognizes the power of its communication channels; calling events too frequently or through unwanted channels may threaten participation and effective communications during rare times of emergency. Therefore, Rhode Island Energy will never call more than three voluntary demand response events in a given year, and will not request voluntary demand response via email, call, or text.

New Pathway!

Rhode Island Energy recognizes the power of crowd sourcing and proposes to use its growing digital presence to encourage peak demand reduction.

Rhode Island Energy does not propose to claim any savings from its voluntary efforts during 2024-2026 for the purposes of shareholder incentives; 100% of the value will go to customers. Rhode Island Energy will use this period to assess the efficacy of calls to action and may propose alternative designs in future years.

Last, Rhode Island Energy recognizes the advocacy groups that have paved the way for voluntary calls for demand response in previous years – thank you for helping us see the value! We hope to work together to amplify our messages in the future.

Commercial and Industrial ("C&I") Track

To participate in the C&I track, customers must be in rate classes C-06, G-02 or G-32; customers in other rates classes are ineligible to participate in the C&I track. Customers in the C-06 rate class may participate in either the RSB or C&I track, but they may not participate in both tracks at the same time or switch to a different track midseason. Participants in the C&I track may participate in either Daily Dispatch, Targeted Dispatch, or both (referred to as "dual enrollment").

Both Daily Dispatch and Targeted Dispatch are technology agnostic. These programs offer flexible avenues of participation that accommodate more complex technologies (e.g., building automation systems, complex lighting controls, etc.) and processes (e.g., deferring production). Furthermore, peak demand reduction achieved through battery energy storage dispatch and electric vehicle demand response are eligible through both C&I pathways.

All peak demand reduction must be environmentally responsible, per LCP Statute and Standards. Therefore, fossil-fueled backup generators are only eligible to count toward performance for the 2024-2026 ConnectedSolutions seasons if they have an active Operating Permit or Minor Source/Preconstruction Permit from the Rhode Island Department of Environmental Management ("RIDEM"). It is important to note that the eligibility requirements will be updated to further limit fossil fuel-based generating emissions during the 2027-2029 program years.[5] Additional guidance and requirements on eligible technologies and fuels will be provided in program documentation prior to each season.

Participants may earn incentives based on actual performance, up to $1 million per participant per year. Incentive structures, levels, and eligibility requirements are discussed further below. This $1 million incentive cap applies to all ConnectedSolutions participants, even participants eligible for the Daily Dispatch $300/kW rate lock.

Proposed Changes

Rhode Island Energy recognizes the growing interest in battery energy storage for commercial and industrial customers. By combining battery energy storage as an eligible peak reduction pathway in Daily Dispatch and Targeted Dispatch, Rhode Island Energy intends for program participation to be streamlined and compensated according to desired participation level.

Rhode Island Energy also seeks to clarify the potential role (or ineligibility) of backup generators and combined heat and power systems in 2024-2026.

Last, Rhode Island Energy hopes to encourage diffuse participation and support equitable planning by imposing a cap on the total annual incentive that may potentially be earned by any single participant.

[5] RIDEM Air Resources

Daily Dispatch

Commercial and industrial customers may enroll in the Daily Dispatch pathway. Daily Dispatch incentivizes participants on a pay-for-performance basis to curtail their electricity demand during the one peak grid load hour of the year, as well as other high and medium peak days in June through September, for a total of no more than 60 events.

Incentive structure and amount:

New participants earn a performance incentive of $275 per kW reduced on average during peak events. It is Rhode Island Energy's intention to offer this multiyear incentive rate for the first five years for new participants, however incentive levels after 2026 are subject to review and approval.

Beginning in 2024, for any Daily Dispatch event in which a participant has a negative load shed, that negative performance will be included in the calculation of the participant's overall average performance for the season. If the participant's overall average performance is a negative value, then the participant will receive no incentive payment for that season.

Multi-Year Incentive Rate for Daily Dispatch

Table 2, below, describes the annual eligible incentive rate for participants depending on year of first enrollment and participation. Note that Rhode Island Energy plans to honor the five-year rate lock for Daily Dispatch customers who enrolled battery assets during or prior to the 2023 season through 2026. Also, please note that the prior five-year incentive lock represents Rhode Island Energy's intentions; it is not a guarantee of incentive levels. Annual incentive levels are subject to change pending review and approval.

2-Year Incentive Commitment Letter

For new battery storage systems larger than 50 kW-AC that do not yet have authority to interconnect, the customer or their vendor can choose to request a 2-year Incentive Commitment Letter from Rhode Island Energy once an interconnection application has been accepted as complete.

Proposed changes

Rhode Island Energy proposes to change the Daily Dispatch incentive level in order to drive more avoided electric bill costs.

Additionally, negative event performances will be included in the average calculation of overall season performance.

The Commitment Letter will lock the incentive rate for the customer during the construction, installation, and interconnection of the battery system for up to a maximum of two years, through the 2026 peak season. Customers who receive a Commitment Letter prior to June 1, 2024, will be eligible to receive the 2023 incentive rate.

When the participant receives authority to interconnect and enrolls in Daily Dispatch, their incentive rate will be the amount committed to in the Commitment Letter, even if the incentive rate has decreased during the construction, installation, and interconnection period or two years, whichever is shorter.

Please note that the Commitment Letter and multiyear incentive rate represents Rhode Island Energy's intentions; it is not a guarantee of incentive levels. Annual incentive levels are subject to change pending review and approval.

Table 2. Daily Dispatch incentive schedule

Customer enrolled and begun peak season participation….	2020	2021	2022	2023	2024	2025	2026	2027*	2028*
2019	$300	$300	$300	$300	$275	$275	$275	TBD	TBD
2020	$300	$300	$300	$300	$300	$275	$275	TBD	TBD
2021	-	$300	$300	$300	$300	$300	$275	TBD	TBD
2022	-	-	$300	$300	$300	$300	$300	TBD	TBD
2023	-	-	-	$300	$300	$300	$300	$300	TBD
2024	-	-	-	-	$300	$300	$300	$300	$300
2024 (Participants enrolled on or after June 1, 2024)					$275	$275	$275	$275	$275

Notes: Each row represents the peak season in which a customer first enrolled and began peak season participation. Each column represents the year of the peak season. The contents of the cells indicate the eligible incentive level in dollars per average kW reduced per peak event across that year's season. For example, a customer who enrolled and begun peak season participation in 2019 had been eligible to receive $300/kW for average kW reduced in years 2020 through 2023, and $275/kW in years 2024-2026. Note that for all customers, incentives will be set in three-year periods "2024-2026". *During the next three-year review, the incentive may be re-evaluated and adjusted based on market conditions for the Program Period 2027-2029. All incentives are subject to review and oversight.

Targeted Dispatch

Commercial and industrial customers may enroll in the Targeted Dispatch program. Targeted Dispatch incentivizes participants on a pay-for-performance basis to curtail their electricity demand during the one peak load hour of the year and other high peak days in June through September, for a total of no more than eight events.

Incentive structure and amount:

Participants earn a performance incentive of $35 per kW reduced on average during peak events. Beginning in 2024, for any Targeted Dispatch event in which a participant has a negative load shed, that negative performance will be included in the calculation of the participant's overall average performance for the season. If the participant's overall average performance is a negative value, then the participant will receive no incentive payment for that season.

Proposed changes

Rhode Island Energy proposes to change this incentive level, from $40 to $35 per kilowatt reduced on average during peak events.

Additionally, negative event performances will be included in the average calculation of overall season performance.

Section 5. Annual Participation, Peak Reduction, and Benefit-Cost Assessment

Rhode Island Energy offers the following anticipated program participation and peak load reduction in Table 3, below.

Table 3. Anticipated participation and peak load reduction

Residential and Small Business Track		**Participants/Devices**		
	Average Load Reduction per Device (kW)	**2024**	**2025**	**2026**
BYOT	0.65	15,379	19,379	23,379
RSB Battery	5.84	862	912	1,062
EVDR	0.32	500	1,250	2,250
Commercial and Industrial Track		**Load Reduction (kW)**		
		2024	**2025**	**2026**
Daily Dispatch		16,114	17,726	19,498
Targeted Dispatch		12,940	13,587	14,266

Notes: The table shows anticipated projections for participation in and peak load reduction resulting from ConnectedSolutions in 2024-2026.

Rhode Island Energy estimates it can deliver this range of participation and associated load reduction for the potential budget in

Table 4, below.

Table 4. Projected programmatic budget

Residential and Small Business Track	**Budget**		
	2024	**2025**	**2026**
BYOT	$3,418,784	$3,578,985	$3,935,939
RSB Battery			
EVDR			
Commercial and Industrial Track	**Budget**		
	2024	**2025**	**2026**
Daily Dispatch	$5,647,131	$5,828,857	$6,366,215
Targeted Dispatch			

Notes: The table shows projected budget for ConnectedSolutions in 2024-2026. Budget includes participant incentives (70-95 percent of total budget) and administration (5-30 percent of total budget, depending on pathway). Budget does not include regulatory allocation or shareholder incentive.

Section 6. Complete Budget, Performance Incentive, Funding Source

The Tables in Appendix 1 provide a complete summary of program costs, impacts, and benefits. Rhode Island Energy proposes to collect funding through the SRP Factor within the EE Charge.

Appendices

Appendix 1. Tables

Table 1
Rhode Island Energy
2024 Demand Response Funding Sources

(1)	**Projected Budget**	**$9,809,938**
	Sources of Other Funding	$0
(2)	Projected Fund Balance and Interest from Previous Year	$0
(3)	Projected FCM Net Revenue from ISO-NE	$0
(4)	**Total Other Funding**	**$0**
(5)	**Customer Funding Required**	**$9,809,938**
(6)	**Forecasted kWh Sales**	**4,404,237,721**
(7)	Demand Response Program Charge per kWh (Excluding Uncollectible Recovery)	$0.00222
(8)	Proposed SRP Opex Factor per kWh (Excluding Uncollectible Recovery)	$0.00000
(9)	Total Proposed Demand Response Charge per kWh (Excluding Uncollectible Recovery)	$0.00222
(10)	Currently Effective Uncollectible Rate	1.3%
(11)	**Proposed Demand Response Program Charge per kWh (Including Uncollectible Recovery)**	**$0.00224**

Notes:

(1) Projected Budget includes regulatory costs which are forecasted by kWh sales.
(2) Total Other Funding equals Line (2) + Line (3).
(3) Customer Funding Required equals Line (1) – Line (4).
(4) Demand Response Program Charge per kWh (Excluding Uncollectible Recovery) equals Line (5) ÷ Line (6), truncated to five decimal places.
(5) Total Proposed Demand Response Charge per kWh (Excluding Uncollectible Recovery) equals Line (7) + Line (8).
(6) Uncollectible rate confirmed in Docket No. 4770.
(7) Proposed Demand Response Program Charge per kWh (Including Uncollectible Recovery) equals Line (9) ÷ (1 – Line (10)), truncated to five decimal places.

Table 2
Rhode Island Energy
2025 Demand Response Funding Sources

		Portfolio
(1)	**Projected Budget**	**$10,450,896**
	Sources of Other Funding	$0
(2)	Projected Fund Balance and Interest from Previous Year	$0
(3)	Projected FCM Net Revenue from ISO-NE	$0
(4)	**Total Other Funding**	**$0**
(5)	**Customer Funding Required**	**$10,450,896**
(6)	**Forecasted kWh Sales**	**7,359,729,627**
(7)	Demand Response Program Charge per kWh (Excluding Uncollectible Recovery)	$0.00142
(8)	Proposed SRP Opex Factor per kWh (Excluding Uncollectible Recovery)	$0.00000
(9)	Total Proposed Demand Response Charge per kWh (Excluding Uncollectible Recovery)	$0.00142
(10)	Currently Effective Uncollectible Rate	1.3%
(11)	**Proposed Demand Response Program Charge per kWh (Including Uncollectible Recovery)**	**$0.00143**

Notes:

(1) Projected Budget includes regulatory costs which are forecasted by kWh sales.

(2) Total Other Funding equals Line (2) + Line (3).
(3) Customer Funding Required equals Line (1) – Line (4).
(4) Demand Response Program Charge per kWh (Excluding Uncollectible Recovery) equals Line (5) ÷ Line (6), truncated to five decimal places.
(5) Total Proposed Demand Response Charge per kWh (Excluding Uncollectible Recovery) equals Line (7) + Line (8).
(6) Uncollectible rate confirmed in Docket No. 4770.
(7) Proposed Demand Response Program Charge per kWh (Including Uncollectible Recovery) equals Line (9) ÷ (1 – Line (10)), truncated to five decimal places.

Table 3
Rhode Island Energy
2026 Demand Response Funding Sources

		Portfolio
(1)	**Projected Budget**	**$11,610,093**
	Sources of Other Funding	$0
(2)	Projected Fund Balance and Interest from Previous Year	$0
(3)	Projected FCM Net Revenue from ISO-NE	$0
(4)	**Total Other Funding**	**$0**
(5)	**Customer Funding Required**	**$11,610,093**
(6)	**Forecasted kWh Sales**	**7,379,396,240**
(7)	Demand Response Program Charge per kWh (Excluding Uncollectible Recovery)	$0.00157
(8)	Proposed SRP Opex Factor per kWh (Excluding Uncollectible Recovery)	$0.00000
(9)	Total Proposed Demand Response Charge per kWh (Excluding Uncollectible Recovery)	$0.00157
(10)	Currently Effective Uncollectible Rate	1.3%
(11)	**Proposed Demand Response Program Charge per kWh (Including Uncollectible Recovery)**	**$0.00159**

Notes:

(1) Projected Budget includes regulatory costs which are forecasted by kWh sales.
(2) Total Other Funding equals Line (2) + Line (3).
(3) Customer Funding Required equals Line (1) – Line (4).
(4) Demand Response Program Charge per kWh (Excluding Uncollectible Recovery) equals Line (5) ÷ Line (6), truncated to five decimal places.
(5) Total Proposed Demand Response Charge per kWh (Excluding Uncollectible Recovery) equals Line (7) + Line (8).
(6) Uncollectible rate confirmed in Docket No. 4770.
(7) Proposed Demand Response Program Charge per kWh (Including Uncollectible Recovery) equals Line (9) ÷ (1 – Line (10)), truncated to five decimal places.

Table 4
Rhode Island Energy
2024 Demand Response Program Budget ($000)

	Program Planning & Administration	Marketing	Rebates and Other Customer Incentives	Sales, Tech Assist & Training	Evaluation & Market Research	Performance Incentive	Grand Total
Residential							
Residential ConnectedSolutions	$100.2	$10.3	$2,614.4	$693.9	$0.0		$3,418.8
Residential Performance Incentive						$108.3	$108.3
Subtotal	**$100.2**	**$10.3**	**$2,614.4**	**$693.9**	**$0.0**	**$108.3**	**$3,527.1**
Commercial & Industrial							
C&I ConnectedSolutions	$89.4	$7.2	$5,250.6	$300.0	$0.0		$5,647.1
Commercial & Industrial Performance Incentive						$363.8	$363.8
Subtotal	**$89.4**	**$7.2**	**$5,250.6**	**$300.0**	**$0.0**	**$363.8**	**$6,010.9**
Portfolio							
EERMC	$108.8						$108.8
OER	$163.2						$163.2
Subtotal	**$272.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$272.0**
Grand Total	**$461.6**	**$17.5**	**$7,865.0**	**$993.9**	**$0.0**	**$472.0**	**$9,809.9**

Notes:

(1) OER budget is equal to 60% of 3% of System Benefits Charge (SBC) collections.
(2) EERMC budget is equal to 40% of 3% of SBC collections.

Table 5
Rhode Island Energy
2025 Demand Response Program Budget ($000)

	Program Planning & Administration	Marketing	Rebates and Other Customer Incentives	Sales, Tech Assist & Training	Evaluation & Market Research	Performance Incentive	Grand Total
Residential							
Residential ConnectedSolutions	$102.0	$10.3	$2,595.7	$871.0	$0.0		$3,579.0
Residential Performance Incentive						$268.7	$268.7
Subtotal	**$102.0**	**$10.3**	**$2,595.7**	**$871.0**	**$0.0**	**$268.7**	**$3,847.7**
Commercial & Industrial							
C&I ConnectedSolutions	$85.9	$7.2	$5,385.8	$350.0	$0.0		$5,828.9
Commercial & Industrial Performance Incentive						$492.1	$492.1
Subtotal	**$85.9**	**$7.2**	**$5,385.8**	**$350.0**	**$0.0**	**$492.1**	**$6,321.0**
Portfolio							
EERMC	$112.9						$112.9
OER	$169.3						$169.3
Subtotal	**$282.2**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$282.2**
Grand Total	**$470.1**	**$17.5**	**$7,981.5**	**$1,221.0**	**$0.0**	**$760.8**	**$10,450.9**

Notes:

(1) OER budget is equal to 60% of 3% of System Benefits Charge (SBC) collections.
(2) EERMC budget is equal to 40% of 3% of SBC collections.

Table 6
Rhode Island Energy
2026 Demand Response Program Budget ($000)

	Program Planning & Administration	Marketing	Rebates and Other Customer Incentives	Sales, Tech Assist & Training	Evaluation & Market Research	Performance Incentive	Grand Total
Residential							
Residential ConnectedSolutions	$103.9	$10.3	$2,788.5	$1,033.3	$0.0		$3,935.9
Residential Performance Incentive						$435.6	$435.6
Subtotal	**$103.9**	**$10.3**	**$2,788.5**	**$1,033.3**	**$0.0**	**$435.6**	**$4,371.6**
Commercial & Industrial							
C&I ConnectedSolutions	$87.5	$7.2	$5,871.6	$400.0	$0.0		$6,366.2
Commercial & Industrial Performance Incentive						$563.2	$563.2
Subtotal	**$87.5**	**$7.2**	**$5,871.6**	**$400.0**	**$0.0**	**$563.2**	**$6,929.4**
Portfolio							
EERMC	$123.6						$123.6
OER	$185.4						$185.4
Subtotal	**$309.1**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$309.1**
Grand Total	**$500.4**	**$17.5**	**$8,660.1**	**$1,433.3**	**$0.0**	**$998.9**	**$11,610.1**

Notes:

(1) OER budget is equal to 60% of 3% of System Benefits Charge (SBC) collections.
(2) EERMC budget is equal to 40% of 3% of SBC collections.

Table 7
Rhode Island Energy
Calculation of 2024 Cost-Effectiveness (Avoided Electric Bill Costs) ($000)

	RI Test Benefit / Cost	Total Benefit	Program Implementation Expenses	Participant Cost	Performance Incentive
Residential					
Residential ConnectedSolutions	1.19	$4,062.8	$3,418.8	$0.0	
Subtotal	**1.15**	**$4,062.8**	**$3,418.8**	**$0.0**	**$108.3**
Commercial & Industrial					
C&I ConnectedSolutions	1.35	$7,635.3	$5,647.1	$0.0	
Subtotal	**1.27**	**$7,635.3**	**$5,647.1**	**$0.0**	**$363.8**
Portfolio					
EERMC			$108.8		
OER			$163.2		
Subtotal			**$272.0**		
Grand Total	**1.19**	**$11,698.1**	**$9,337.9**	**$0.0**	**$472.0**

Notes:

(1) Total Benefits are based on avoided electric bill cost only.

Table 8
Rhode Island Energy
Calculation of 2025 Cost-Effectiveness (Avoided Electric Bill Costs) ($000)

	RI Test Benefit / Cost	Total Benefit	Program Implementation Expenses	Participant Cost	Performance Incentive
Residential					
Residential ConnectedSolutions	1.41	$5,029.8	$3,579.0	$0.0	
Subtotal	**1.31**	**$5,029.8**	**$3,579.0**	**$0.0**	**$268.7**
Commercial & Industrial					
C&I ConnectedSolutions	1.45	$8,464.4	$5,828.9	$0.0	
Subtotal	**1.34**	**$8,464.4**	**$5,828.9**	**$0.0**	**$492.1**
Portfolio					
EERMC			$112.9		
OER			$169.3		
Subtotal			**$282.2**		
Grand Total	**1.29**	**$13,494.2**	**$9,690.1**	**$0.0**	**$760.8**

Table 9
Rhode Island Energy
Calculation of 2026 Cost-Effectiveness (Avoided Electric Bill Costs) ($000)

	RI Test Benefit / Cost	Total Benefit	Program Implementation Expenses	Participant Cost	Performance Incentive
Residential					
Residential ConnectedSolutions	1.58	$6,232.2	$3,935.9	$0.0	
Subtotal	**1.43**	**$6,232.2**	**$3,935.9**	**$0.0**	**$435.6**
Commercial & Industrial					
C&I ConnectedSolutions	1.47	$9,373.3	$6,366.2	$0.0	
Subtotal	**1.35**	**$9,373.3**	**$6,366.2**	**$0.0**	**$563.2**
Portfolio					
EERMC			$123.6		
OER			$185.4		
Subtotal			**$309.1**		
Grand Total	**1.34**	**$15,605.6**	**$10,611.2**	**$0.0**	**$998.9**

Table 10
Rhode Island Energy
Calculation of 2024 Cost-Effectiveness (Societal Benefits, Excluding Economic) ($000)

	RI Test Benefit / Cost	Total Benefit	Program Implementation Expenses	Participant Cost	Performance Incentive
Residential					
Residential ConnectedSolutions	2.70	$9,230.6	$3,418.8	$0.0	
Subtotal	**2.62**	**$9,230.6**	**$3,418.8**	**$0.0**	**$108.3**
Commercial & Industrial					
C&I ConnectedSolutions	3.10	$17,501.6	$5,647.1	$0.0	
Subtotal	**2.91**	**$17,501.6**	**$5,647.1**	**$0.0**	**$363.8**
Portfolio					
EERMC			$108.8		
OER			$163.2		
Subtotal			**$272.0**		
Grand Total	**2.73**	**$26,732.2**	**$9,337.9**	**$0.0**	**$472.0**

Table 11
Rhode Island Energy
Calculation of 2025 Cost-Effectiveness (Societal Benefits, Excluding Economic) ($000)

	RI Test Benefit / Cost	Total Benefit	Program Implementation Expenses	Participant Cost	Performance Incentive
Residential					
Residential ConnectedSolutions	2.87	$10,255.8	$3,579.0	$0.0	
Subtotal	**2.67**	**$10,255.8**	**$3,579.0**	**$0.0**	**$268.7**
Commercial & Industrial					
C&I ConnectedSolutions	2.98	$17,375.2	$5,828.9	$0.0	
Subtotal	**2.75**	**$17,375.2**	**$5,828.9**	**$0.0**	**$492.1**
Portfolio					
EERMC			$112.9		
OER			$169.3		
Subtotal			**$282.2**		
Grand Total	**2.64**	**$27,630.9**	**$9,690.1**	**$0.0**	**$760.8**

Table 12
Rhode Island Energy
Calculation of 2026 Cost-Effectiveness (Societal Benefits, Excluding Economic) ($000)

	RI Test Benefit / Cost	Total Benefit	Program Implementation Expenses	Participant Cost	Performance Incentive
Residential					
Residential ConnectedSolutions	3.22	$12,656.4	$3,935.9	$0.0	
Subtotal	**2.90**	**$12,656.4**	**$3,935.9**	**$0.0**	**$435.6**
Commercial & Industrial					
C&I ConnectedSolutions	3.01	$19,158.3	$6,366.2	$0.0	
Subtotal	**2.76**	**$19,158.3**	**$6,366.2**	**$0.0**	**$563.2**
Portfolio					
EERMC			$123.6		
OER			$185.4		
Subtotal			**$309.1**		
Grand Total	**2.74**	**$31,814.7**	**$10,611.2**	**$0.0**	**$998.9**

Table 13
Rhode Island Energy
Summary of 2024 Avoided Electric Bill Costs by Program ($000)

	Benefits (000's)											
		Capacity				Energy						
		Summer	Capacity			Summer		Winter		Electric Energy		Energy Price
	Total	Generation	DRIPE	Transmission	Distribution	Peak	Off Peak	Peak	Off Peak	DRIPE	Avoided RNS	Arbitrage
Residential												
Residential ConnectedSolutions	$4,063	$1,050	$331	$204	$1,823	$6	$0	$0	$0	$0	$585	$64
Subtotal	**$4,063**	**$1,050**	**$331**	**$204**	**$1,823**	**$6**	**$0**	**$0**	**$0**	**$0**	**$585**	**$64**
Commercial & Industrial												
C&I ConnectedSolutions	$7,635	$2,008	$633	$389	$3,486	$0	$0	$0	$0	$0	$1,119	$0
Subtotal	**$7,635**	**$2,008**	**$633**	**$389**	**$3,486**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,119**	**$0**
Grand Total	**$11,698**	**$3,058**	**$964**	**$593**	**$5,309**	**$6**	**$0**	**$0**	**$0**	**$0**	**$1,703**	**$64**
Avoided Electric Bill Cost ($/kW)		$ 69.11	$ 21.79	$ 13.40	$ 120.00	$ 0.64	$ -	$ -	$ -	$ 0.03	$ 38.50	$ 12.73

Total for Batteries ($/kW)	**$ 275.53**
Total for Thermostats ($/kW)	**$ 263.47**
Total for the Rest ($/kW)	**$ 262.80**

Notes:

(1) Energy Values are for Thermostats only.
(2) Energy Price Arbitrage only applies to RSB Battery Pathway.

Table 14
Rhode Island Energy
Summary of 2025 Avoided Electric Bill Costs by Program ($000)

	Benefits (000's)											
		Capacity				Energy						
		Summer	Capacity			Summer		Winter		Electric Energy		Energy Price
	Total	Generation	DRIPE	Transmission	Distribution	Peak	Off Peak	Peak	Off Peak	DRIPE	Avoided RNS	Arbitrage
Residential												
Residential ConnectedSolutions	$5,030	$1,318	$411	$249	$2,228	$8	$0	$0	$0	$0	$747	$69
Subtotal	**$5,030**	**$1,318**	**$411**	**$249**	**$2,228**	**$8**	**$0**	**$0**	**$0**	**$0**	**$747**	**$69**
Commercial & Industrial												
C&I ConnectedSolutions	$8,464	$2,252	$703	$425	$3,808	$0	$0	$0	$0	$0	$1,276	$0
Subtotal	**$8,464**	**$2,252**	**$703**	**$425**	**$3,808**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,276**	**$0**
Grand Total	**$13,494**	**$3,570**	**$1,114**	**$674**	**$6,036**	**$8**	**$0**	**$0**	**$0**	**$0**	**$2,023**	**$69**
Avoided Electric Bill Cost ($/kW)		$ 71.93	$ 22.44	$ 13.58	$ 121.62	$ 0.62	$ -	$ -	$ -	$ 0.03	$ 40.75	$ 12.90

Total for Batteries ($/kW)	**$ 283.22**
Total for Thermostats ($/kW)	**$ 270.97**
Total for the Rest ($/kW)	**$ 270.32**

Table 15
Rhode Island Energy
Summary of 2026 Avoided Electric Bill Costs by Program ($000)

	Benefits (000's)											
		Capacity				Energy						
		Summer	Capacity			Summer		Winter		Electric Energy		Energy Price
	Total	Generation	DRIPE	Transmission	Distribution	Peak	Off Peak	Peak	Off Peak	DRIPE	Avoided RNS	Arbitrage
Residential												
Residential ConnectedSolutions	$6,232	$1,636	$511	$304	$2,726	$10	$0	$0	$0	$0	$962	$81
Subtotal	**$6,232**	**$1,636**	**$511**	**$304**	**$2,726**	**$10**	**$0**	**$0**	**$0**	**$0**	**$962**	**$81**
Commercial & Industrial												
C&I ConnectedSolutions	$9,373	$2,498	$781	$465	$4,162	$0	$0	$0	$0	$0	$1,469	$0
Subtotal	**$9,373**	**$2,498**	**$781**	**$465**	**$4,162**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,469**	**$0**
Grand Total	**$15,606**	**$4,134**	**$1,292**	**$769**	**$6,888**	**$10**	**$0**	**$0**	**$0**	**$0**	**$2,431**	**$81**
Avoided Electric Bill Cost ($/kW)		$ 73.97	$ 23.12	$ 13.76	$ 123.26	$ 0.68	$ -	$ -	$ -	$ 0.03	$ 43.50	$ 13.08

Total for Batteries ($/kW)	**$ 290.69**
Total for Thermostats ($/kW)	**$ 278.32**
Total for the Rest ($/kW)	**$ 277.61**

Table 16
Rhode Island Energy
Summary of 2024 Load Reduction and Energy Savings by Program

	Load Reduction (kW)		Electric Energy Savings MWh	
	Summer	**Winter**	**Annual**	**Lifetime**
Residential				
Residential ConnectedSolutions	15,190	0	130	130
Subtotal	**15,190**	**0**	**130**	**130**
Commercial & Industrial				
C&I ConnectedSolutions	29,054	0	0	0
Subtotal	**29,054**	**0**	**0**	**0**
Grand Total	**44,244**	**0**	**130**	**130**

Table 17
Rhode Island Energy
Summary of 2025 Load Reduction and Energy Savings by Program

	Load Reduction (kW)		Electric Energy Savings MWh	
	Summer	Winter	Annual	Lifetime
Residential				
Residential ConnectedSolutions	18,322	0	164	164
Subtotal	**18,322**	**0**	**164**	**164**
Commercial & Industrial				
C&I ConnectedSolutions	31,312	0	0	0
Subtotal	**31,312**	**0**	**0**	**0**
Grand Total	**49,635**	**0**	**164**	**164**

Table 18
Rhode Island Energy
Summary of 2026 Load Reduction and Energy Savings by Program

	Load Reduction (kW)		Electric Energy Savings MWh	
	Summer	Winter	Annual	Lifetime
Residential				
Residential ConnectedSolutions	22,118	0	198	198
Subtotal	**22,118**	**0**	**198**	**198**
Commercial & Industrial				
C&I ConnectedSolutions	33,764	0	0	0
Subtotal	**33,764**	**0**	**0**	**0**
Grand Total	**55,883**	**0**	**198**	**198**

Table 19
Rhode Island Energy
Summary of 2024 PIM Benefits

2024 PIM Benefits									
	Electric Energy			Capacity					
	Summer								
	Peak	Off Peak	Electric Energy DRIPE	Summer Generation	Capacity DRIPE	Transmission	Distribution	RNS	Energy price arbitrage
Residential	$6,427	$0	$265	$1,049,865	$330,947	$203,519	$1,822,852	$584,832	$64,096
Residential Connected Solutions	$6,427	$0	$265	$1,049,865	$330,947	$203,519	$1,822,852	$584,832	$64,096
Commercial & Industrial	$0	$0	$0	$2,008,022	$632,985	$389,260	$3,486,475	$1,118,577	$0
C&I Connected Solutions	$0	$0	$0	$2,008,022	$632,985	$389,260	$3,486,475	$1,118,577	$0
Total	$6,427	$0	$265	$3,057,887	$963,932	$592,779	$5,309,326	$1,703,409	$64,096
Percent Application in PIM	100%	100%	100%	100%	100%	100%	100%	100%	100%

Notes:

(1) Total PIM Benefits are based on avoided electric bill cost only.

Table 20
Rhode Island Energy
Summary of 2025 PIM Benefits

2025 PIM Benefits									
	Electric Energy			Capacity					
	Summer								
	Peak	Off Peak	Electric Energy DRIPE	Summer Generation	Capacity DRIPE	Transmission	Distribution	RNS	Energy price arbitrage
Residential	**$7,825**	**$0**	**$334**	**$1,317,988**	**$411,171**	**$248,790**	**$2,228,332**	**$746,639**	**$68,728**
Residential ConnectedSolutions	$7,825	$0	$334	$1,317,988	$411,171	$248,790	$2,228,332	$746,639	$68,728
Commercial & Industrial	**$0**	**$0**	**$0**	**$2,252,395**	**$702,676**	**$425,174**	**$3,808,140**	**$1,275,979**	**$0**
C&I ConnectedSolutions	$0	$0	$0	$2,252,395	$702,676	$425,174	$3,808,140	$1,275,979	$0
Total	**$7,825**	**$0**	**$334**	**$3,570,383**	**$1,113,847**	**$673,964**	**$6,036,473**	**$2,022,618**	**$68,728**
Percent Application in PIM	100%	100%	100%	100%	100%	100%	100%	100%	100%

Notes:

(1) Total PIM Benefits are based on avoided electric bill cost only.

Table 21
Rhode Island Energy
Summary of 2026 PIM Benefits

2026 PIM Benefits									
	Electric Energy			Capacity					
	Summer								
	Peak	Off Peak	Electric Energy DRIPE	Summer Generation	Capacity DRIPE	Transmission	Distribution	RNS	Energy price arbitrage
Residential	**$10,401**	**$0**	**$403**	**$1,636,169**	**$511,365**	**$304,383**	**$2,726,258**	**$962,152**	**$81,111**
Residential ConnectedSolutions	$10,401	$0	$403	$1,636,169	$511,365	$304,383	$2,726,258	$962,152	$81,111
Commercial & Industrial	**$0**	**$0**	**$0**	**$2,497,649**	**$780,610**	**$464,647**	**$4,161,694**	**$1,468,746**	**$0**
C&I ConnectedSolutions	$0	$0	$0	$2,497,649	$780,610	$464,647	$4,161,694	$1,468,746	$0
Total	**$10,401**	**$0**	**$403**	**$4,133,818**	**$1,291,975**	**$769,030**	**$6,887,951**	**$2,430,898**	**$81,111**
Percent Application in PIM	100%	100%	100%	100%	100%	100%	100%	100%	100%

Notes:

(1) Total PIM Benefits are based on avoided electric bill cost only.

Table 22
Rhode Island Energy
2024 Demand Response PIM ($000)

	Performance Incentive				
	Eligible Benefits: 100% Avoided Electric Bill Costs	Eligible Costs	Eligible Net Benefits	Design Payout Rate	Design Performance Payout
Residential	$4,063	$3,521	$541	20.0%	$108
Commercial & Industrial	$7,635	$5,817	$1,819	20.0%	$364
Total	**$11,698**	**$9,338**	**$2,360**	**20.0%**	**$472**

Table 23
Rhode Island Energy
2025 Demand Response PIM ($000)

	Performance Incentive				
	Eligible Benefits				
	100% Avoided Electric Bill Costs	Eligible Costs	Eligible Net Benefits	Design Payout Rate	Design Performance Payout
Residential	$5,030	$3,686	$1,343	20.0%	$269
Commercial & Industrial	$8,464	$6,004	$2,461	20.0%	$492
Total	**$13,494**	**$9,690**	**$3,804**	**20.0%**	**$761**

Table 24
Rhode Island Energy
2026 Demand Response PIM ($000)

	Performance Incentive				
	Eligible Benefits				
	100% Avoided Electric Bill Costs	Eligible Costs	Eligible Net Benefits	Design Payout Rate	Design Performance Payout
Residential	$6,232	$4,054	$2,178	20.0%	$436
Commercial & Industrial	$9,373	$6,557	$2,816	20.0%	$563
Total	**$15,606**	**$10,611**	**$4,994**	**20.0%**	**$999**

Table 25
Rhode Island Energy
Comparison of 2023 and 2024-2026 Budget

Program Implementation Costs ($000)						
		2023	**2024**	**2025**	**2026**	**Three Year Total**
Residential ConnectedSolutions	**TOTAL**	*$1,963.1*	*$3,527.1*	*$3,847.7*	*$4,371.5*	*$11,746.3*
Program Planning & Administration		$ 82.6	$ 100.2	$ 102.0	$ 103.9	$ 306.1
Sales, Tech Assist & Training		$ 346.1	$ 693.9	$ 871.0	$ 1,033.3	$ 2,598.2
Marketing		$ 11.5	$ 10.3	$ 10.3	$ 10.3	$ 30.9
Evaluation & Market Research		$ 19.2	$ -	$ -	$ -	$ -
Incentives		$ 1,503.7	$ 2,614.4	$ 2,595.7	$ 2,788.5	$ 7,998.6
Performance Incentive		$ -	$ 108.3	$ 268.7	$ 435.6	$ 812.6
C&I ConnectedSolutions	**TOTAL**	*$6,079.0*	*$6,010.9*	*$6,321.0*	*$6,929.4*	*$19,261.3*
Program Planning & Administration		$ 167.8	$ 89.4	$ 85.9	$ 87.5	$ 262.8
Sales, Tech Assist & Training		$ 152.2	$ 300.0	$ 350.0	$ 400.0	$ 1,050.0
Marketing		$ 6.8	$ 7.2	$ 7.2	$ 7.2	$ 21.5
Evaluation & Market Research		$ 14.4	$ -	$ -	$ -	$ -
Incentives		$ 5,737.8	$ 5,250.6	$ 5,385.8	$ 5,871.6	$ 16,508.0
Performance Incentive		$ -	$ 363.8	$ 492.1	$ 563.2	$ 1,419.1
Other	**TOTAL**	*$ 241.3*	*$ 272.0*	*$ 282.2*	*$ 309.0*	*$ 863.2*
EERMC		$ 96.5	$ 108.8	$ 112.9	$ 123.6	$ 345.3
OER		$ 144.8	$ 163.2	$ 169.3	$ 185.4	$ 517.9
TOTAL		**$ 8,283.4**	**$ 9,810.0**	**$ 10,450.8**	**$ 11,610.0**	**$ 31,870.8**

Notes:

(1) The 2023 EERMC and OER allocation was included in the regulatory contributions within Docket No. 22-33 Rhode Island Energy Efficiency Plan.

Appendix 2. Notes on Terminology

Least-Cost Procurement Standards
The version of the Least-Cost Procurement Standards in effect for 2024-2026 is the version adopted by Order [TBD] in Docket No. 23-07-EE: https://ripuc.ri.gov/Docket-23-07-EE.

The following definitions are excerpted from the Least-Cost Procurement Standards for convenient reference:

> System Reliability Procurement
> Procurement to meet or mitigate a gas or electric system need or optimization from a party other than the gas or electric utility[6] that provides the need or optimization by employing diverse energy resources, distributed generation, or demand response.[7]
>
> Utility Reliability Procurement
> Procurement to meet or mitigate a gas or electric system need or optimization that is not System Reliability Procurement is a utility investment.[8]
>
> System Needs
> i. Electric System Needs: Needs to serve both customer load and customer generation, including, but not limited to, system capacity (normal and emergency), voltage performance, reliability performance, protection coordination, fault current management, reactive power compensation, asset condition assessment, distributed generation constraints, operational considerations, and customer requests.
> ii. Gas System Needs: Needs to serve customers, including, but not limited to, system capacity (normal and emergency), pressure management, asset condition assessment, gas service that supports electric distributed generation, and operational considerations.
>
> Optimization of System Performance
> Improvement of the performance and efficiency[9] of the gas or electric system that includes enhanced reliability, peak load reduction, improved utilization of both utility and non-utility assets, optimization of operations, and reduced system losses.

---

6 A utility proposal to own and operate non-traditional investment or new operations and maintenance services, such as new voltage-regulation equipment, battery storage, or vegetation management, and any vendor services associated with such investment or service, shall not be considered System Reliability Procurement per this definition. Such investments and services are, however, still subject to the Guidance Document issued in Docket No. 4600A.

7 Including, but not limited to, the resources named in R.I. Gen. Laws § 39-1-27.7(a)(1)(i)-(iii).

8 For example, many such Utility Reliability Procurement investments and operations are proposed in annual Infrastructure, Safety, and Reliability Plans filed pursuant to R.I. Gen. Laws § 39-1-27.7.1(c)(2).

9 Efficiency includes both long- and short-term cost efficiency.

Rhode Island Energy further annotates the following terminology to aid in understanding of this *2022 SRP Year-End Report*:

Non-Wires/Non-Pipes Alternative
Outdated terms referring to non-wires/non-pipes solution.

Non-Wires/Non-Pipes Solution
A solution that satisfies a System Need or Optimization of System Performance through means other than utility-owned infrastructure.

Non-Wires/Non-Pipes Opportunity
A System Need or Optimization of System Performance that may be satisfied via a Non-Wires/Non-Pipes Solution (i.e., the electric or gas screening criteria has been met).

Non-Wires/Non-Pipes Project Proposal
A proposal for a specific Non-Wires/Non-Pipes Solution for a specific Non-Wires/Non-Pipes Opportunity (i.e., such as a proposal submitted in response to a Request for Proposals).

Non-Wires/Non-Pipes Project
A specific Non-Wires/Non-Pipes Solution for a specific Non-Wires/Non-Pipes Opportunity (i.e., such as a project in the process of being constructed, installed, or otherwise implemented).

Non-Wires/Non-Pipes Program
The process by which Rhode Island Energy identifies non-wires/non-pipes opportunities, solicits and evaluates non-wires/non-pipes project proposals, and submits funding requests with relevant justification and documentation for non-wires/non-pipes projects.

Wires/Pipes Solution
A solution that satisfies a System Need or Optimization of System Performance through utility-owned infrastructure.

SRP Investment Proposal
A filing describing a Non-Wires/Non-Pipes Project per Chapter 5 of the Least-Cost Procurement Standards.

Utility Performance Incentive
Shared value between customers and Company shareholders.

Appendix 3. Legal and Regulatory Basis

Least-Cost Procurement Statute[10]
System reliability procurement is contemplated in Rhode Island's Least-Cost Procurement statute. Some key relevant excerpts from this statute are below for convenient reference.

"§ 39-1-27.7. System reliability and least-cost procurement.

(a) Least-cost procurement shall comprise system reliability and energy efficiency and conservation procurement, as provided for in this section, and supply procurement, as provided for in § 39-1-27.8, as complementary but distinct activities that have as common purpose meeting electrical and natural gas energy needs in Rhode Island, in a manner that is optimally cost-effective, reliable, prudent, and environmentally responsible.

(b) The commission shall establish not later than June 1, 2008, standards for system reliability and energy efficiency and conservation procurement that shall include standards and guidelines for:

(1) System reliability procurement, including but not limited to:
(i) Procurement of energy supply from diverse sources, including, but not limited to, renewable energy resources as defined in chapter 26 of this title;
(ii) Distributed generation, including, but not limited to, renewable energy resources and thermally leading combined heat and power systems, that is reliable and is cost-effective, with measurable, net system benefits;
(iii) Demand response, including, but not limited to, distributed generation, back-up generation, and on-demand usage reduction, that shall be designed to facilitate electric customer participation in regional demand response programs, including those administered by the independent service operator of New England ("ISO-NE"), and/or are designed to provide local system reliability benefits through load control or using on-site generating capability;
(iv) To effectuate the purposes of this division, the commission may establish standards and/or rates (A) For qualifying distributed generation, demand response, and renewable energy resources; (B) For net metering; (C) For back-up power and/or standby rates that reasonably facilitate the development of distributed generation; and (D) For such other matters as the commission may find necessary or appropriate.

(4) Each electrical and natural gas distribution company shall submit to the commission on or before September 1, 2008, and triennially on or before September 1 thereafter through September 1, 2028, a plan for system reliability and energy efficiency and conservation procurement…"

[10] R.I. Gen Laws 39-1-27.7 http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-27.7.HTM

Least-Cost Procurement Standards – Chapter 5

Chapter 5 of the Rhode Island Public Utilities Commission's "Least-Cost Procurement Standards," approved and adopted pursuant to Order No. [TBD] in Docket No. 23-07-EE (LCP Standards), describes the intent, purpose, content, orders, and timing of *SRP Investment Proposals*. This Chapter is copied below for convenient reference.

"5.1 Intent

A. This Chapter provides standards and guidelines for System Reliability Procurement investment proposals (SRP Proposals) that are consistent with Three-Year SRP Plans filed pursuant to Chapter 4.

B. This Chapter does not require that all System Reliability Procurement investments identified in a Three-Year SRP Plan must be funded through an SRP Proposal.[11]

5.2 Purpose

A. SRP Proposals will present specific implementation of a System Reliability Procurement investment.

B. SRP Proposals will present specific costs of investments, specific funding plans, and, if applicable, proposals for cost recovery.

C. SRP Proposals will identify any established incentives that the specific investment is eligible for.

5.3 Content

A. Testimony

i. The distribution company will prefile testimony on the following:

a. how the Plan is consistent with the requirements of Section 1.3;

b. updated and specific information required in Sections 4.4.A.ii.a through d, 4.4.A.iv, and 4.4.A.v relevant to the investment(s);

c. costs, a funding plan, and proposed cost recovery; and

d. the specific approvals the distribution company is requesting from the PUC.

[11] For example, in some instances, the investment may appropriately be funded through an Annual EE Plan.

5.4 Orders

A. The PUC will approve SRP Proposals that meet these Standards.

B. The PUC may deny approval of investment proposals that do not meet these Standards and that are not critically lined to the cost-effectiveness of other investments that are otherwise consistent with these Standards.

C. The PUC will order adoption of any other proposals supported by the SRP Proposal and consistent with Least-Cost Procurement, and all applicable statutes, rules, and policies.

5.5 Timing

A. The PUC does not limit the timing of SRP Proposals, but prefers that the proposals be filed alongside, but separately from, annual Infrastructure, Safety, and Reliability Plans."

Least-Cost Procurement Standards – Section 1.3

Section 1.3 of the Rhode Island Public Utilities Commission's "Least-Cost Procurement Standards," approved and adopted pursuant to Order No. [TBD] in Docket No. 23-07-EE (LCP Standards), establishes principles and stipulations for the assessment of cost, cost-effectiveness, reliability, prudency, and environmental responsibility of system reliability procurement solutions. This Chapter is copied below for convenient reference.

"A. Least-Cost Procurement shall be cost-effective, reliable, prudent, and environmentally responsible. Least-Cost Procurement that is Energy Efficiency and Conservation Procurement shall also be lower than the cost of additional energy supply. System Reliability Procurement shall be lower than the cost of the best alternative Utility Reliability Procurement.

B. When preparing any cost test or resource assessment, including the RI Test, the following principles will be applied:

i. Supply-side and demand-side alternative energy resources shall be compared in a consistent and comprehensive manner.

ii. Cost tests shall be created using the RI Framework and account for applicable policy goals, as articulated in legislation, PUC orders, regulations, guidelines, and other policy directives.

iii. Cost tests shall account for all relevant, important impacts, even those that are 5 difficult to quantify and monetize. Where applicable cost or benefit categories cannot be quantified, such categories shall be qualitatively assessed.[12]

iv. Cost tests shall be symmetrical, for example, by including both costs and benefits for each relevant type of impact.

v. Analyses of the impacts of investments shall be forward-looking, capturing the difference between costs and benefits that would occur over the life of the investments with those that would occur absent the investments. Sunk costs and benefits are not relevant to a cost-effectiveness analysis.

vi. Cost tests shall be completely transparent and should fully document and reveal all relevant inputs, assumptions, methodologies, and results.

C. Cost-Effective

i. The PUC shall determine cost-effectiveness in a manner consistent with the PUC's Guidance Document issued in Docket No. 4600A.

ii. The distribution company shall assess the cost-effectiveness of measures, programs, and portfolios of Least-Cost Procurement. All categories of the RI Test are applicable to cost-effectiveness, although some categories may have no or unknown value. The distribution company shall assess cost-effectiveness using, at a minimum, the following two cost-effectiveness analyses:

   a. An analysis that, for categories with value or cost that is shared between Rhode Island Energy and other jurisdictions (both within the state and region), presents benefits and costs without allocating them between Rhode Island Energy and other jurisdictions;

   b. An analysis that, for categories with value or cost that is shared between Rhode Island Energy and other jurisdictions (both within the state and region), presents only those benefits and costs that will be allocated to Rhode Island Energy.

iii. The distribution company shall provide the specific benefit- and cost-factors included in determining the RI Test ratios.

iv. With respect to the value of greenhouse gas reductions, the RI Test shall include the costs of greenhouse gas emissions mitigation (measured in CO2 equivalents) as they

[12] Qualitative assessments may include relative descriptions of magnitude and direction.

are imposed and are projected to be imposed by the Regional Greenhouse Gas Initiative, Rhode Island Renewable Energy Standard and Rhode Island Act on Climate, and any other utility system costs associated with reasonably anticipated future greenhouse gas reduction requirements at the state, regional, or federal level for both electric and gas programs. The RI Test shall also include the costs and benefits of other emissions and their generation or reduction through Least Cost Procurement. The RI Test may include the value of greenhouse gas reduction not embedded in any of the above.

v. Benefits and costs that are projected to occur over the term of the Least-Cost Procurement investment shall be stated in present value terms in the RI Test calculation, using a discount rate that appropriately reflects the risks of the investment of customer funds in Least-Cost Procurement. Energy efficiency is a low-risk resource in terms of cost of capital risk, project risk, and portfolio risk.

D. Reliable

i. The distribution company shall assess the
   a. ability of Least-Cost Procurement investments to meet the energy supply or delivery system needs.
   b. ability of previous investments, including identical or similar investments, to support the conclusion that a new investment is reliable, and
   c. potential for implementation issues, including available workforce, market continuity, program scalability.

ii. As applicable, the distribution company also shall assess an investment's
   a. ability to meet specific identified system needs;
   b. anticipated reliability as compared to alternatives;
   c. operational complexity and flexibility;
   d. resiliency of the system;
   e. risks associated with investment (for example, the ability to obtain licensing and permitting, significant risks of stranded investment, the potential risk reduction of a more incremental approach, sensitivity of alternatives to differences in load forecasts, and emergence of new technologies, etc.);
   f. risks associated with customers' behavior, responsiveness, and ability to potentially modify usage at certain times and seasons; and
   g. relative changes in other risks that are applicable to the investment, such as reduced (or increased) public safety risk. The distribution company shall supply any other information that the company believes supports a finding that an investment is reliable.

E. Prudent

i. The distribution company shall assess:

a. how the investment supports the goals of the electric or natural gas system and the purposes of Least-Cost Procurement.
b. potential for synergy savings based on alternatives that address multiple needs;
c. how the entire investment proposal affects the risks of ratepayers and the distribution company;
d. how the investment effectively uses available funding sources and integrates with energy programs and policies; and
e. how the investment is equitable in consideration of the allocation of costs, the allocation of benefits, customer access, and customer participation. This shall be done by, at minimum, assessing which groups have historically received disproportionately lower benefits from LCP investments and by presenting other appropriate, quantifiable metrics that describe how an investment is equitable.

ii. The distribution company shall provide rate impacts to a range of customer types and usage levels, and shall provide bill impacts, and shall provide how these impacts were considered in the proposed investment.

iii. The distribution company may provide additional cost tests to support a finding that an investment is prudent.

iv. The distribution company shall supply any other information that the company believes supports a finding that an investment is prudent.

F. Environmentally Responsible

i. The distribution company shall assess how investment complies with State environmental and climate policies and shall properly value environmental and climate costs and benefits.

ii. The distribution company shall assess how the investment affects environmental and climate pollution, where applicable, at a local, regional, and global scale.

G. Lower than the Cost of Additional Supply (omitted)

H. Lower than the cost of the best alternative Utility Reliability Procurement

i. The distribution company shall compare the cost of System Reliability Procurement measures, programs, and/or portfolios to the cost of the best alternative Utility Reliability Procurement option using all applicable costs enumerated in the RI Framework. The distribution company shall provide specific costs included in the Cost of System Reliability Procurement.

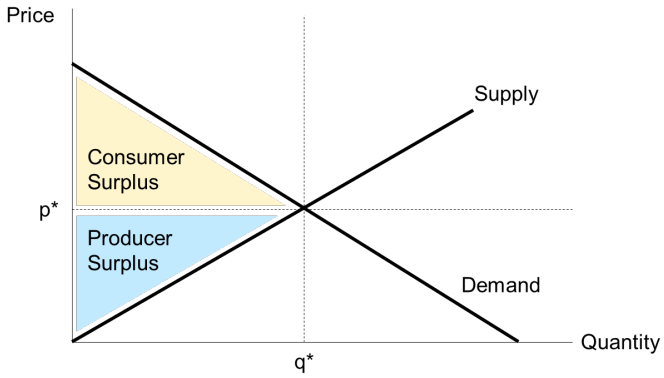
ii. At a minimum, the comparison shall include the applicable cost categories in a Total Resources Cost Test.

iii. he distribution company shall describe which costs in the RI Framework were included in the cost of System Reliability Procurement and which costs are included in the alternative Utility Reliability Procurement. For any categories that are not included in either, the distribution company shall describe why these categories are not included."

Appendix 4. Technical Appendix

Conceptual approach

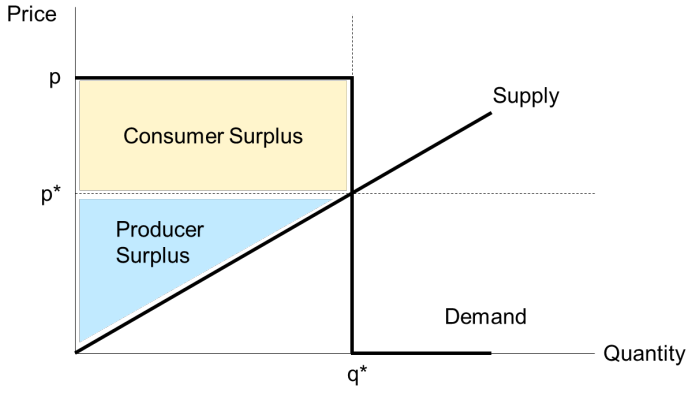
Program design can be modeled conceptually as a set of economic supply and demand curves across pathways. Let us first start with a single pathway. The simple economic model, depicted below, plots price against quantity:



The demand curve (in this simple depiction, a line) slopes from the top left corner of the graph, representing a high price for the first units of quantity demanded, to the bottom right corner of the graph, representing a low price for the last units of quantity demanded. The supply curve (also a line in this simple depiction) slopes from the bottom left corner of the graph, representing a low cost to produce the first few units, to the top right corner of the graph, representing a high cost to produce the last few units. The supply and demand curves intersect at quantity demanded, q*, and price, p*. At equilibrium, producers will sell q* units of a good or service at price p*; consumers will buy those q* units of that good or service at price p*. The area represented in yellow, called consumer surplus, represents the value consumers receive as defined by the difference between the maximum price the consumer would be willing pay and the price actually paid, for all q* units. The area represented in blue, called producer surplus, represents the value producers receive as defined by the difference between the minimum price the producer would be willing accept and the price actually accepted for all q* units. Together, consumer surplus plus producer surplus represents the value gained by everyone in the market.[13]

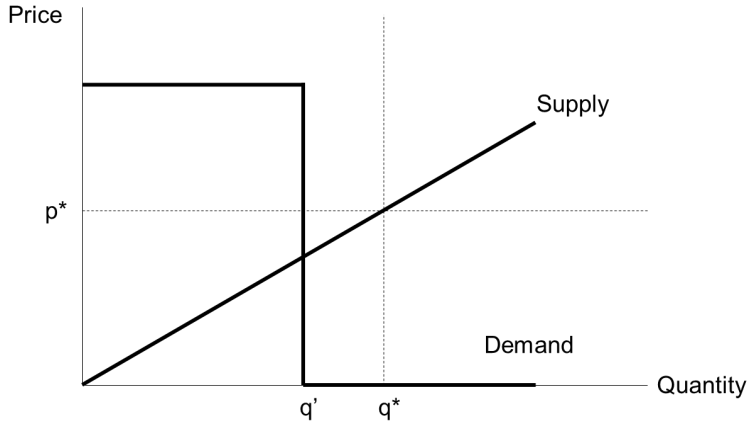
For the purposes of program design, Rhode Island Energy is the sole consumer in the market. The service being purchased is peak demand reduction at some price p (measured in dollars) and in some quantity q (measured in kilowatts, kW). The producers are the program participants that reduce peak demand in exchange for an incentive payment (whether structured as an upfront enrollment incentive, a pay-for-performance incentive, a financing incentive, etc.). We can draw a more specific supply and demand graph for a specific pathway in the program:

[13] This simplified explanation omits discussion of market failures like externalities; there may be non-monetary value that accrues to consumers, producers, or entities who are not part of the market that is not reflected here. Further discussion on this topic below.

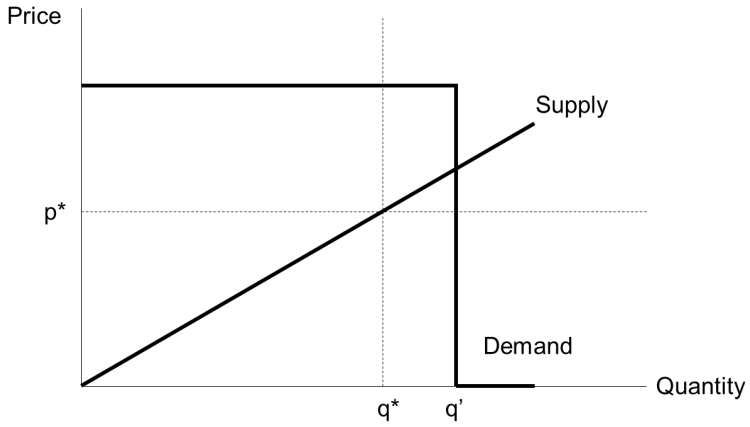


The demand curve represents Rhode Island Energy's maximum willingness to pay for peak demand reduction through this pathway. For up to q* units, Rhode Island Energy is willing to pay price p. After q* units are procured, Rhode Island Energy's willingness to pay drops to zero. The supply curve is depicted as a simple upward-sloping line, but in reality may be a more complex curve based on the actual economics and decision-making of program participants. Consumer and producer surplus are shown in yellow and blue, respectively.

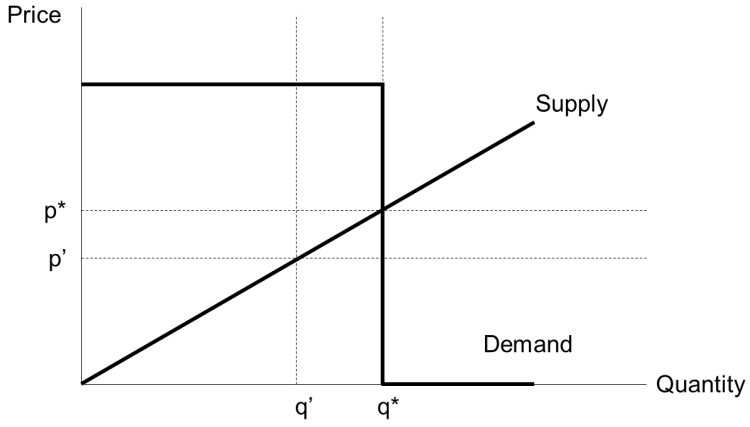
As the sole consumer and the program designer, Rhode Island Energy is charged with determining an appropriate quantity q* to procure and an appropriate price p* to pay. In the above graph, the quantity q* may represent a constraint, such as only having enough budget to buy q* units. The following four graphs show some of the factors that contribute to setting p* and q* (the incentive level and the quantity to be procured), and the resulting outcomes of imperfect program design.



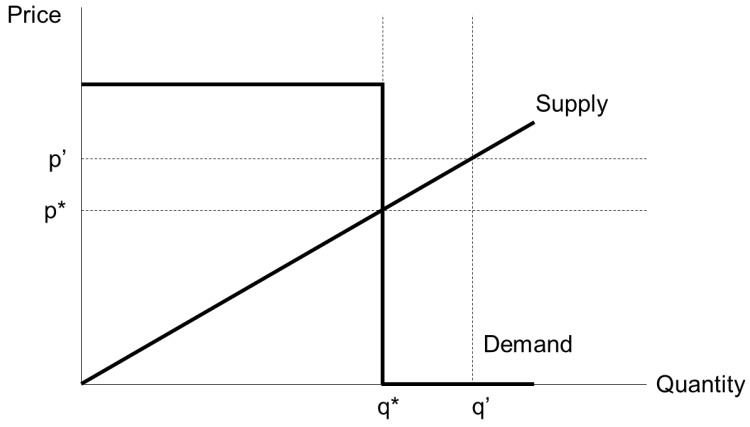
If we size the pathway too small (q'<q*), then we risk not getting as much low-cost peak demand reduction as we could. Resulting effects may include the pathway being oversubscribed, spending more than budgeted, collecting less funding than needed, and turning away potential participants.



If we size the pathway too big (q'>q*), then there is the risk that the incentive is too low to fully subscribe q'. The result may be undersubscription, collecting from customers than ultimately spent, and delivering lower value than planned.

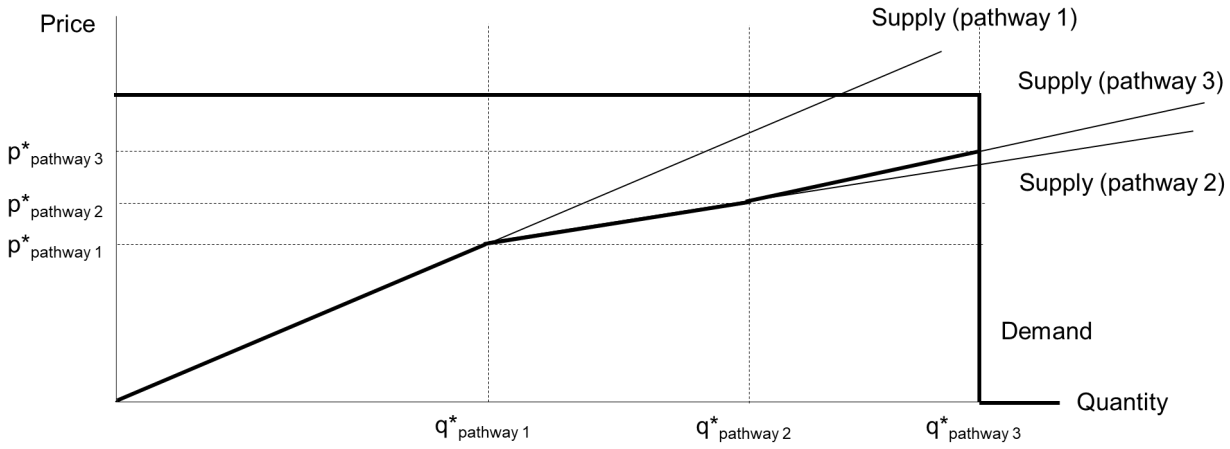


If we set the incentive rate too low (p'<p*), then the incentive will not be sufficient to encourage the level of participation and peak demand expected. The result may be that the pathway is undersubscribed (q'<q*), resulting in overcollections from customers and lower value than planned.



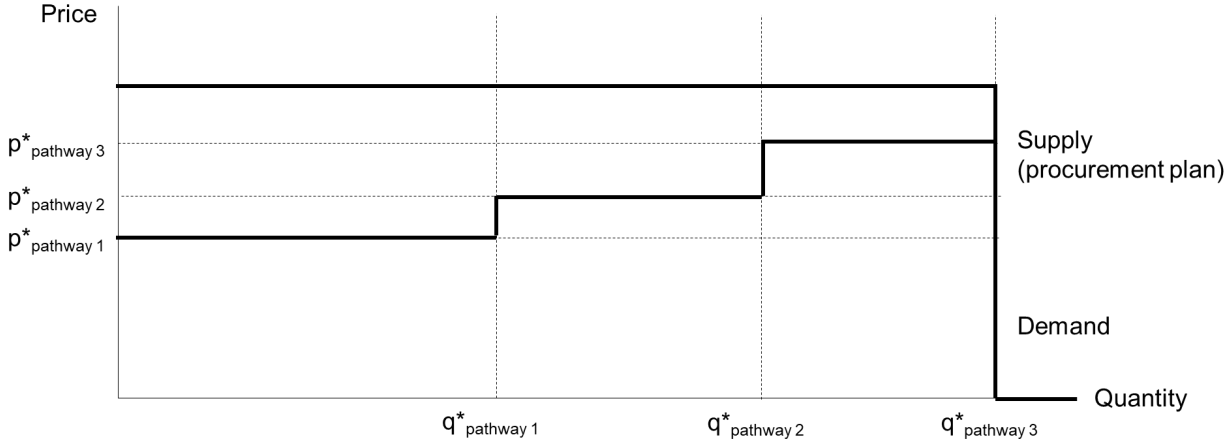
If we set the incentive rate too high (p'>p*), then we risk having the pathway be oversubscribed, which means under-collecting program funding from customers and potentially turning would-be participants away.

The program is an aggregation of pathways. To model the program, we order the pathways from lowest price p* to highest price p* and concatenate the supply and demand curves associated with the quantity q* proposed to be procured through each pathway. The figure below models supply and demand curves for a program consisting of three pathways.

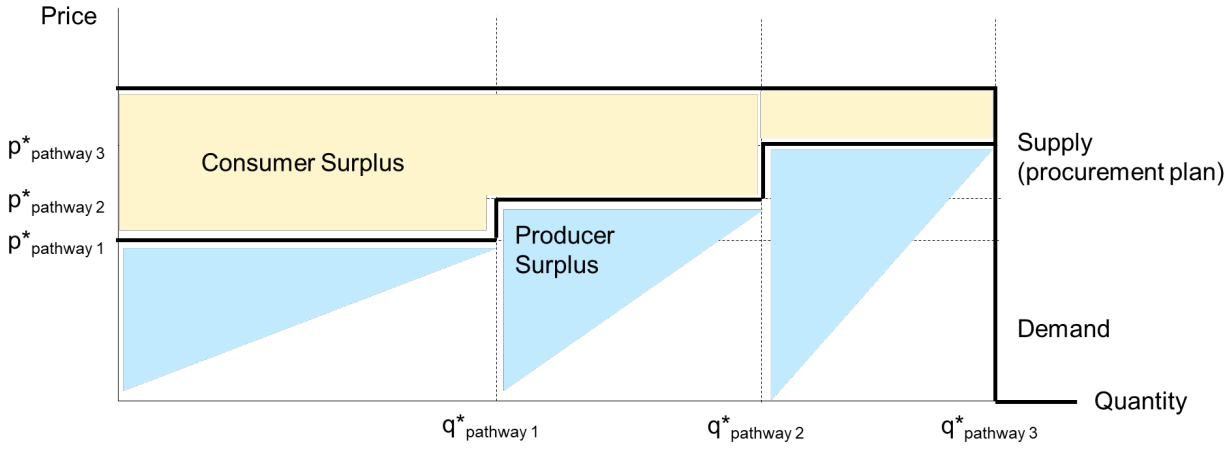


In our model, our willingness to pay for a unit of peak demand reduction is the same across all pathways; this embodies the program design principle to be technology agnostic.

Similarly, we can depict our proposed procurement plan based on the incentive p* available for q* units to be procured through each pathway:



In this model, consumer surplus is depicted by the yellow area, representing the value gained by paying a price p* that is less than our maximum willingness to pay.[14] Producer surplus is depicted by the blue area, representing the value gained by program participants for reducing peak demand.[15]

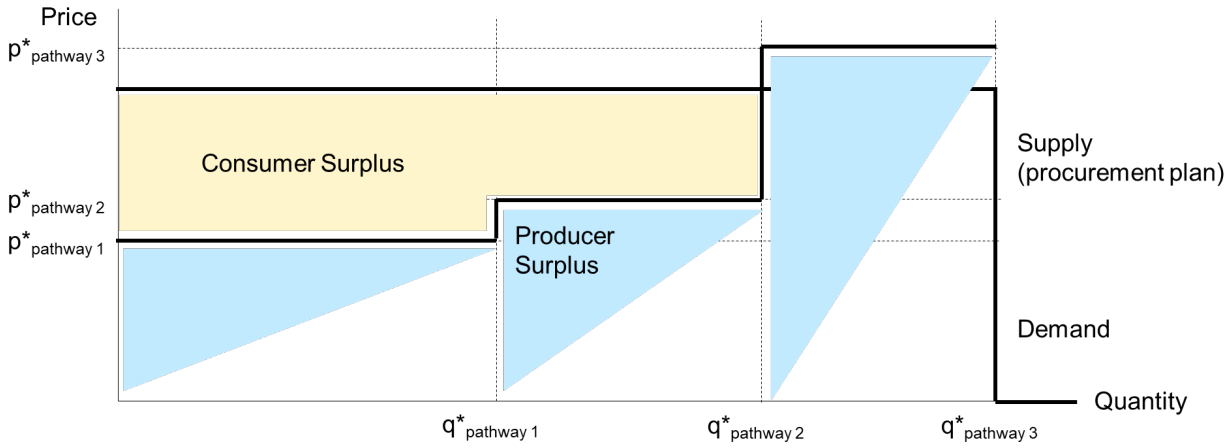


[14] Although we model Rhode Island Energy as the sole consumer in this market, the value of the consumer surplus actually flows to Rhode Island Energy customers (in the form of lower electric bills; see discussion on setting willingness to pay). Rhode Island Energy proposes to share a portion of this value with its shareholders (in the form of a performance incentive; see discussion in associated pre-filed testimony).

[15] Note that producer surplus may be wholly gained by participants (e.g., a participant gets 100 percent of the incentive for setting their thermostat back for peak events) or shared between participants and third parties (e.g., a participant enters into a contract with a vendor in which the vendor receives a portion of the participant's incentive payout in exchange for the vendor's support in reducing the participant's peak demand). Regarding the latter, Rhode Island Energy is not party to such agreements and therefore makes no assumptions about the structure or sharing of the producer surplus in such instances. 100 percent of value not captured by utility bills is retained by society (e.g., customers and non-customers, with the exact mix dependent on the value category).

As program designer, Rhode Island Energy seeks to maximize consumer surplus subject to applicable constraints, such as budget constraints, statutory and regulatory constraints, and market constraints.[16, 17] The budget constraint is derived from how much is feasible and prudent to collect from customers to fund this program given the whole of existing rates and anticipated bill impacts. Statutory and regulatory constraints are derived from compliance with applicable statutes and regulations (i.e., Least-Cost Procurement). Market constraints capture the availability of quantity able to be produced and may be affected by the availability of enabling technologies (e.g., Bring Your Own Thermostats) and workforce.

It is insightful to also model the case in which the cost of procuring peak demand through a pathway exceeds willingness to pay, illustrated below. In this case, the producer surplus grows and the consumer surplus shrinks. Such a procurement plan may be justified in a number of instances, such as if there are anticipated returns on investment (e.g., lower cost peak demand reduction available in future procurements), non-modeled value that is external to the transaction (e.g., the value of local jobs and macroeconomic activity), or other bases.



16 Rhode Island Energy focuses on maximizing consumer surplus because of its company mission (and statutory franchise obligation) to deliver affordable electric service to all customers. Producer surplus accrues only to the subset of participating customers and their vendors. In theory, a program designer with a societal perspective could conduct a dual maximization across consumer and producer surplus; such an exercise would be complex and would require a level of market data and insight that is not available at this time. Although Rhode Island Energy takes a predominantly utility perspective, we acknowledge the incremental value of the various pathways. (Indeed, if Rhode Island Energy were to take a strict utility perspective, we would procure as much of the least expensive peak demand reduction as possible and zero demand reduction that is more costly than willingness to pay. Given an indifference curve mapped between quantity of peak demand reduction via less costly thermostats and more costly batteries, with a budget constraint, a purely utility perspective planner would put the entirety of their budget toward peak reduction from thermostats.)

17 Academically, this is modeled as utility (i.e., value) maximization subject to constraint, which optimizes quantities procured across pathways rather than in isolation for each pathway.

The following sections of this technical appendix dig into the above conceptual framework as applied to proposed program design for 2024-2026. First, we discuss our determination of willingness to pay. Then, we estimate and adjust the price available p* for peak demand reduction in each pathway. Finally, we set target quantity q* to procure from each pathway.

Willingness to pay

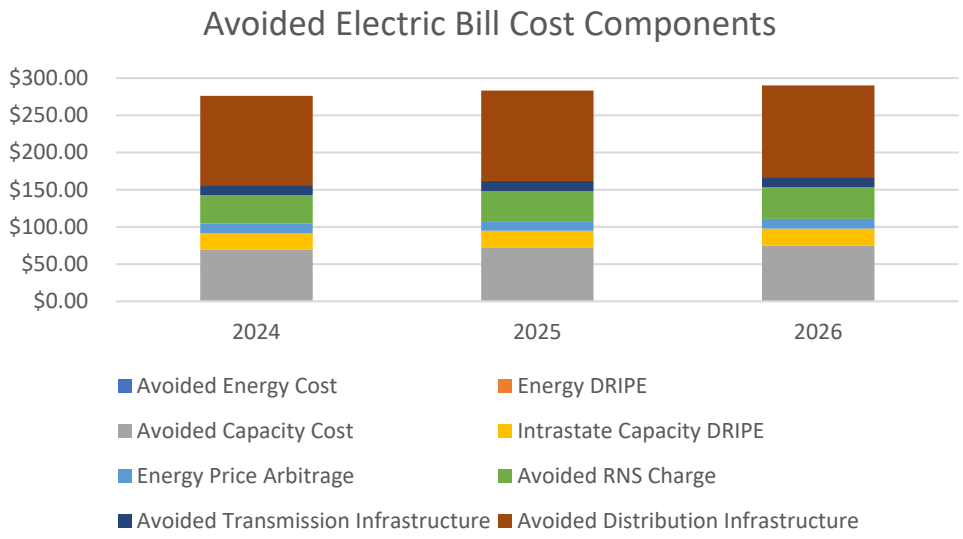
Rhode Island Energy's willingness to pay for a unit of peak demand reduction is equivalent to the cost our customers would otherwise pay for us to serve that unit of demand during peak. These values are specifically limited to costs that would materialize on customer electric bills: energy costs and associated demand reduction induced price effects (DRIPE), energy price arbitrage, capacity costs and associated intrastate DRIPE, Regional Network Service (RNS) charges, transmission infrastructure cost, and distribution infrastructure costs.
The table below shows the value stack for each year of the planning period.[18] Avoided energy and capacity costs and associated intrastate DRIPE are derived from the 2021 Avoided Energy Supply Cost (AESC) Study,[19] adjusted for inflation using an inflation rate of 1.35 percent. We use intrastate DRIPE to reflect the limitation of our perspective to Rhode Island customers. Energy price arbitrage was estimated using ISO-NE wholesale energy price data for 2021-2023, assuming 85 percent round-trip battery efficiency and comparing the difference in average price between the highest price 90 hours and the rest of the summer hours. Avoided RNS charges are prorated for three months based on ISO-NE values. Avoided transmission infrastructure cost is derived using the methodology recommended by the 2021 AESC Study. Avoided distribution infrastructure cost is set at $120/kW in 2024 based on the approximate average of the past four years of avoided costs (2021-2024), each determined using the method recommended by the 2021 AESC Study). Avoided distribution infrastructure cost is scaled by inflation to determine values for 2025 and 2026.

[18] Please note that although cents and decimals are included in figures, this level of detail is not intended to imply precision to the hundredths place.

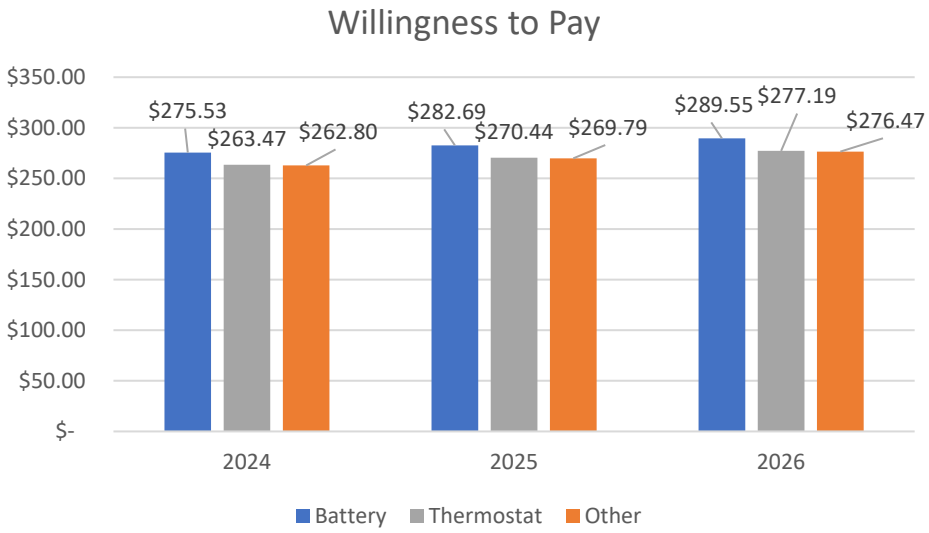
[19] The 2024 version of the AESC Study is anticipated to be published in early February.

Value Category	**2024**	**2025**	**2026**
Avoided Energy Costs	$0.64/kW	$0.62/kW	$0.68/kW
Energy DRIPE	$0.03/kW	$0.03/kW	$0.03/kW
Energy Price Arbitrage	$12.73/kW	$12.90/kW	$13.08/kW
Avoided Capacity Costs	$69.11/kW	$71.93/kW	$73.97/kW
Intrastate Capacity DRIPE	$21.79/kW	$22.44/kW	$23.12/kW
Avoided RNS Charge	$38.50/kW	$40.21/kW	$42.35/kW
Avoided Transmission Infrastructure	$13.40/kW	$13.58/kW	$13.76/kW
Avoided Distribution Infrastructure	$120.00/kW	$121.62/kW	$123.26/kW
Totals			
Battery	$275.53/kW	$282.68/kW	$289.54/kW
Thermostat	$263.47/kW	$270.43/kW	$277.17/kW
Other	$262.80/kW	$269.78/kW	$276.46/kW

The above table is illustrated in the figure below:



The avoided electric bill costs are different for batteries relative to other measures. Batteries include energy price arbitrage in their value stack but not avoided energy costs or DRIPE. The figure below shows the value stack for batteries (blue), thermostats (gray), and non-batteries (orange) in 2024-2026:



For program design purposes, Rhode Island Energy used the smallest value, $262/kW. For budgeting purposes, Rhode Island Energy used the relevant value for year and technology.

Incentive levels

The team estimated unit cost ($/kW) for a unit of peak demand reduction in each pathway in each year. More specifically, unit costs are determined for each incentive level in each pathway (since, in some pathways, participants may receive different incentive levels). There are four components of unit cost: incentive cost, financing cost, administration cost, and regulatory allocation.

The incentive cost is determined by normalizing the incentive level ($) by the expected peak demand reduction (kW). Expected peak demand reduction is based on actual performance of prior year devices: a thermostat reduces 0.65 kW, a battery reduces 5.84 kW, and a participating electric vehicle reduces 0.32 kW.[20] Incentive levels for RSB batteries and C&I track pathways are set by kW so do not need to be normalized.

The financing cost is determined by normalizing the cost of the HEAT loan ($) across the expected peak reduction in the RSB pathway (kW). The HEAT loan is only available to participants in the RSB pathway, so its costs are not normalized by the peak reduction expected

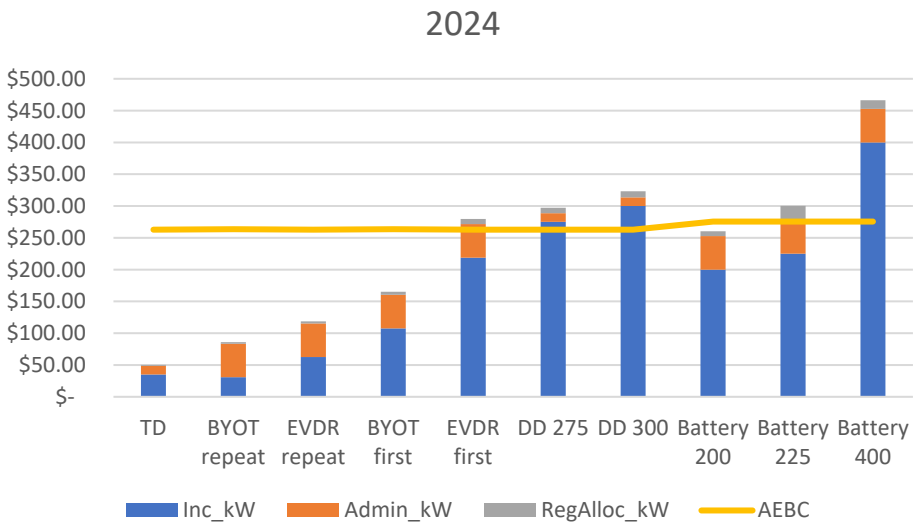
[20] Derived from participant data outside of Rhode Island.

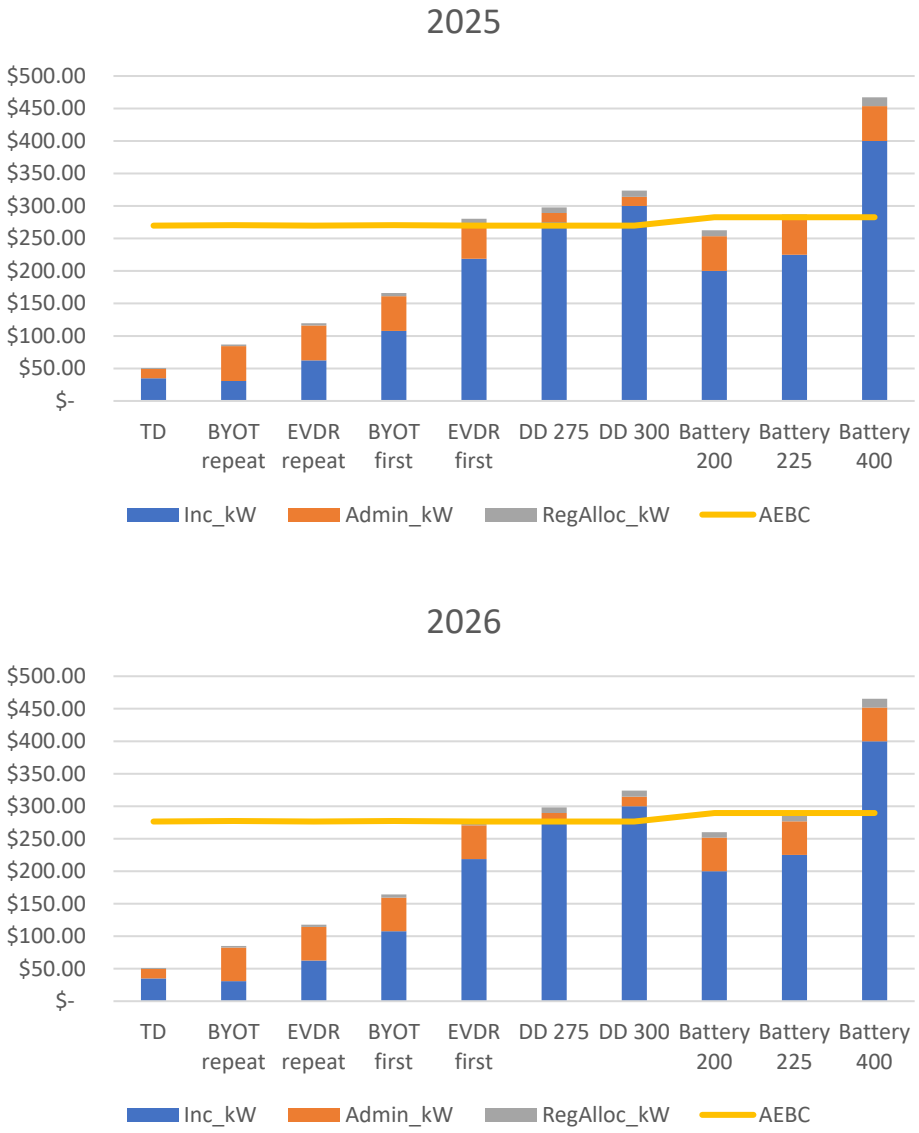
from other pathways. The cost of the HEAT loan is considered to be contained within the first year of an eligible participant's participation and sunk in future years of participation. The cost of the HEAT loan includes the cost of the interest buy-down, a monthly administrative fee, and a charge per loan.

The administration cost is determined by normalizing all non-incentive, non-financing costs ($) across the expected peak demand reduction (kW) in each track. Administration costs are normalized by track instead of by pathway because administration is sufficiently separable by track but not by pathway.

Together, the incentive cost, financing cost, and administration cost equal the program cost. The regulatory allocation is three percent of the program cost, applied to each pathway.

The figures below show the unit cost of reducing peak demand by 1 kw for each pathway (bars) compared to the avoided electric bill cost (AEBC, the line). Financing cost is omitted from these figures; financing cost ranges from $472/kW in 2024 to $22/kW in 2026.





The value created in terms of avoided electric bill costs is calculated by subtracting the unit cost (P) of procuring a unit (kW) of peak demand reduction from the relevant estimate of avoided electric bill cost (AEBC), with the difference multiplied by the number of units (Q) proposed to be procured through that pathway. Value to be shared is the sum across all pathways.

$$Value = \sum_{pathway} \left(\left(AEBC - P_{pathway} \right) * Q_{pathway} \right)$$

Schedule 2: Benefit-Cost Assessment (Excel File)

Introduction and Summary

In this document, Rhode Island Energy summarizes its engagement with stakeholders regarding its *System Reliability Procurement Investment Proposal ("SRP Investment Proposal") for 2024-2026 Electric Demand Response ("ConnectedSolutions")*.

Rhode Island Energy began discussing the role of electric demand response within system reliability procurement in its *2024-2026 SRP Three-Year Plan* first draft, circulated to external stakeholders on July 28, 2023. In its second draft of the *2024-2026 SRP Three-Year Plan,* circulated to external stakeholders on September 6, 2023, and filed with the Rhode Island Public Utilities Commission on November 17, 2023, in Docket No. 23-47-EE, Rhode Island Energy included a preliminary conceptual draft of its *SRP Investment Proposal*.

Rhode Island Energy circulated its initial draft *SRP Investment Proposal* to external stakeholders on November 9, 2023, and provided its initial draft benefit-cost assessment model to the Energy Efficiency and Resource Management ("Council") and Division of Public Utilities and Carriers ("Division") on November 29, 2023. Rhode Island Energy presented its draft *SRP Investment Proposal* at the Council's November 16, 2023, meeting. Rhode Island Energy circulated its second draft *SRP Investment Proposal* and associated benefit-cost assessment model to external stakeholders on January 19, 2024. Discussion held and public comment provided at a meeting of the Energy Efficiency and Resource Management Council ("EERMC" or "the Council") on January 25, 2024.

The intended filing target date of February 8, 2024.

Summary of Stakeholder Circulation and Comments

Rhode Island Energy has discussed its SRP Investment Proposal with several external stakeholders.[1] This section summarizes engagement by avenue of engagement.

Email:

Rhode Island Energy emailed the November 9th version of the SRP Investment Proposal to all participating curtailment service providers ("CSPs") on November 10, 2023, to the Solar Stakeholder distribution list maintained by the Rhode Island Office of Energy Resources ("OER") on December 1, 2023. Rhode Island Energy has also exchanged ad hoc emails with a number of CSPs and other external stakeholders regarding the SRP Investment Proposal during this time.

Rhode Island Energy emailed the January 18th version of the SRP Investment Proposal to the EERMC and the consultant team on January 19, 2024. On January 22, 2024 the draft was also provided to all participating CSPs and the Solar Stakeholder distribution list maintained by OER.

One-on-One Meetings/Calls:

Rhode Island Energy has engaged in remote meetings and calls with five CSPs, two developers, three solar and battery installers, and one customer representative since September 2023. Rhode Island Energy also met with the consultants representing the Council regarding its draft benefit-cost assessment model on November 29, 2023 and January 30, 2024.

SRP Technical Working Group:

Rhode Island Energy and stakeholder members of the SRP Technical Working Group focused its discussion on the initial draft SRP Investment Proposal during its November 15, 2023, meeting. Rhode Island Energy discussed the second draft SRP Investment Proposal with the SRP Technical Working Group at its January 10, 2024, meeting, focusing on the estimation of components of avoided electric bill cost.

Council Meetings:

Rhode Island Energy presented its initial draft SRP Investment Proposal to the Council during its November 16, 2023, meeting. Following discussion, the Council voted to table a vote on whether to endorse the SRP Investment Proposal until its January 25, 2024, meeting. Rhode Island Energy discussed the second draft SRP Investment Proposal with the Council at its January 25, 2024, meeting and also voted to table a vote until its February 21, 2024 meeting.

[1] 1/29 – Endurant and CPower; 1/24 – Sunrun; 1/17 – Endurant and CPower; 1/5 – Sunrun; 1/3 – Newport Solar; 12/15 – Endurant and CPower; 12/14 – Smart Green; 12/13 – CPower; 12/6 – Endurant and CPower; 12/6 – solar stakeholder email; 11/29 – met with c-team on BCA; 11/22 – NEC; 11/16 – EERMC; 11/15 – SRP TWG; 11/13 – Tim Roughan on behalf of Holliston Sand; 11/13 – CPower; 11/10 – Leap; 11/7 – NEC; 11/3 – Total Energies; 10/18 – Enel; 10/16 – CPower; 10/11 – Voltus; 9/28 – Endurant

Written Comments were received from:

1. CPower
2. Enphase Energy
3. Northeast Clean Energy Council (NECEC)
4. Newport Solar
5. Smart Green Solar
6. Sunrun
7. NEC Solar
8. Sol Power

Comments received from stakeholders can be found by accessing the direct link in text above.

Response to Comments Provided to the Council
Due to the volume of comments received, and the fact that many commentors raised similar or the same arguments and considerations for or against the proposal, we have paraphrased similar comments. The numbers following each comment correspond with the list above. This section contains detailed responses to written stakeholder comments:

General Comments and Program Design

Comment: Commentors thanked Rhode Island Energy for leading the SRP development process and for the opportunity to provide feedback on the proposed changes to the ConnectedSolutions program design. Commentors believe some plan modifications identified below are needed. (1, 3)

Response: Rhode Island Energy thanks commentor for robust stakeholder participation and meaningful feedback on program design.

Comment: Commentor expressed concerns over program design principles. The program design principles seem to contradict one another. You cannot be agnostic towards technology and participants and encourage diffuse and diverse participation for reliable response and comply with least-cost procurement standards. This leads to a lower cost for some renewable energy sources and greater cost for others just to ensure an even distribution of technologies. This does not result in the lowest cost solution and limits the potential growth of technologies that may offer better solutions. (5)

Response: Rhode Island energy does not differentiate a kilowatt reduced by one technology or participant from a kilowatt reduced by another technology or participants. While each kilowatt of peak demand reduction is considered to be equal, achieving each kilowatt of peak demand reduction may require different levels of action or opportunity cost on the part of the participant. Rhode Island Energy's third program design principle posits that incentives should be right-sized to spur action; because different methods of reducing peak load require different burdens, it makes sense to differentiate incentive levels. Doing so will minimize program costs while achieving the same peak demand reduction. Rhode Island Energy has to balance the program costs (i.e., the incentive level, financing support, and administration costs) with the benefits (i.e., avoiding costs that would

otherwise materialize on customers' electricity bills to determine the program size and incentives.

Five-Year Rate Lock and Multiyear Incentive Rate

Comment: Commentors have noted the importance of expected cash flows in financial planning and procurement decisions for demand response investments, like battery energy storage systems. Commentors recommend the Company consider maintaining a five-year rate lock or extend the rate lock past five years. (1, 2, 3, 4, 5)

Response: We recognize the importance of mitigating the reduction in incentives from one year to the next. In prior program years, the Company had advertised a "five-year rate lock" whereby participants could expect to receive the same incentive levels as their first year of enrollment in years two through five. While we have removed the 5-year rate lock, the Company intends to honor the "five-year rate lock" for existing participants and is proposing a multiyear incentive rate for new participants.

The Company is attempting to provide more clarity and transparency with transitioning to the term "multiyear incentive rate." By removing the work "lock," the Company intends to make it clearer that incentive levels offered past the current proposal are subject to change. Although the Company intends to maintain incentive levels for five years from the year of enrollment, the Company reserves the right to amend incentive levels if warranted.

Comment: Commentors requested extending the rate lock past five years. Some commentors recommend a 10-year lock-in period. (1, 2, 4, 5)

Response: The Company intends to honor the five-year rate lock and will be offering a multiyear incentive rate. Sharing of risk between developers and stakeholders about future value, especially absent performance guarantees to which we can plan accordingly at scale. To offset potential perceived reduction in certainty from potential participants, the Company is extending the duration for which it is proposing and requesting approval for ConnectedSolutions (three years instead of one year).

Comment: Commentors expressed the need to reduce customer exposure of uncertainty regarding their future revenue stream. The five-year rate lock should freeze both the incentive rate and the performance calculation for the rate lock period. (1, 2, 3, 4, 5)

Response: This comment gets to a philosophical issue about distribution of risk. A long-term rate lock mitigates financial risk for developers. The flip side of the coin is that customers (who fund ConnectedSolutions) take on that risk. At the heart of the risk is our expectation of changes in value of peak load reduction. If we expect peak reduction to gain in value, then a long-term rate lock is potentially mutually beneficial to both developers (who can appreciate the financial certainty) and customers (who expect to get more value for the same cost in the future). If we expect peak reduction to decline in

value, then a long-term rate lock is beneficial to developers (who can appreciate the financial certainty) but is potentially harmful to customers (who get less value over time for the same cost).

This overly simplified example does not include layers of complexity like changes in technology cost, supplemental value streams, or competing priorities for customer funding. Recognizing our current markets are not static (i.e., battery energy storage is arguably not yet a mature market, pending increases in visibility and control of the electric grid may result in new value stacks, and state climate and clean energy policies are driving fundamental changes in our relationship with the electric system), Rhode Island Energy does not feel it is appropriate to commit future customer funding to incentive levels based on the paradigm today. Rhode Island Energy is comfortable in offering steady incentives from 2024-2026 but considers reevaluating those incentives for 2027-2029 as part of its due diligence. We recognize that this is not ideal for developers, but this is the compromise we feel most reasonably balances the interests of program participants and our customers broadly. We are open to revisiting this program design element in future years.

In the meanwhile, we think it is important to frame the longevity of the incentives in terms of likely value of regional coincident peak reduction. Developers (and their financial backers) should not consider ConnectedSolutions to be a transient program. While we are only proposing to guarantee incentives for 2024-2026, we are committed to deriving value from peak reduction as long as there is value to be derived. Therefore, there is an incredibly low probability that incentives will be null in 2027. It may be appropriate for developers to look to expectations about the value of future peak reduction to inform their predictions about potential future revenue from peak reduction.

Incentive Rates and Schedule

Comment: Commentors made clear that the Company's prior proposal would have led to significant disruptions in the market which would negatively affect local battery developers and installers. These disruptions would have been arguably inconsistent with the LCP Standard of prudency. (2, 3, 4, 5, 6, 8)

Response: The Company revised its proposal to delay the cutover date from the old incentive rate to the new incentive rate and to allow for a more gradual phase down of incentive rates for this pathway over two years. We are proposing a cutover of June 1, 2024, to determine whether old or new rates apply. This revision provides more time for battery developers and installers to account for and communicate new rates to their customers over the 4–6 month lead time of customer acquisition. In this example, the Company considered the corollary value of having a healthy battery market qualitatively in influencing program design.

Comment: Commentors requested incentive rates not be decreased for the battery pathway and that rates be guaranteed for longer periods of time. (2, 3, 4, 5, 8)

Response: In the Company's original proposal, it decreased the incentive rate from $400/kW to $200/kW. The Company analyzed the incentive unit cost for each pathway. The residential and small business pathway has the highest unit cost. These unit costs are factored into the proposed program design in two ways. First the Company generally proposes to procure more of lower-cost peak demand reduction and less of higher-cost peak demand reduction (residential batteries). Second, the Company proposes modifications to incentive levels and program design intended to reduce unit costs of pathways that are higher than the Company's willingness to pay. The willingness to pay is the maximum price the Company is willing to pay for a unit of peak demand reduction. On average serving 1 kW of peak load in 2024 would cost the customer base approximately $262. Therefore, the Company reconsidered the original proposal of $200/kW and the filing proposal offers new customers enrolled on or after June 1, 2024 an incentive rate of $225/kW. Participants who have reached their 5th summer of enrollment will receive an annual incentive rate of $200/kW. As discussed in previous responses, it is Rhode Island Energy's intention to uphold a multi-year rate commitment of 5 years for any new participants, however incentive levels are subject to regulatory review and approval.

Financial Expectations/Battery Economics

Comment: Commentors expressed the key role the ConnectedSolutions Program has played in customers' decision to add energy storage to their home or business. Installing battery storage is an expensive undertaking that greatly benefits from economics of scale, so a battery incentive should also encourage the development of battery systems. Customers use program revenues to recoup investments in the battery. Changes and abrupt reduction in incentive rates may substantially reduce participation and further discourage interest in battery installations.

Notably, C&I batteries are increasingly owned and financed by a third-party investor who funds the battery with the expectation that the majority of the return on capital invested will come from revenues generated from the ConnectedSolutions Program, while the customer realizes on-bill savings and resilience. In short, ConnectedSolutions revenues are foundational to the investment; without them, the project is not economically viable.

Commentors outline the role of battery storage and the role they play in reducing electricity supply costs and avoiding electric system infrastructure investments, and local resiliency. (1, 2, 3, 4, 5, 7, 8)

Response: We recognize the underlying policy implications on battery adoption but stress that the role of ConnectedSolutions is not a policy role. The express objective of ConnectedSolutions is to reduce regional coincident peak demand; the objective is not to incentivize battery energy storage adoption. We prefer to incentivize peak-reduction pathways that are less expensive over pathways that are more expensive, regardless of the pathway's technology. That said, we appreciate the insight regarding financial expectations – we hope that moving from a program proposed on an annual basis to a

program proposed on a triennial basis might help provide a little more stability in financial expectations.

We actually anticipate negligible overall attrition of participating battery resources due to the proposed lower incentive. As you describe in these comments, batteries are a significant investment that likely require multiple years of revenue to break even. Given the choice between not participating (incremental revenue of $0) and participating (incremental revenue of $200/kW - $300/kW achieved on average across the season), it is reasonable to expect participation to prevail. It is possible that the expected growth in participation may be lower due to a reduced incentive, but we suspect federal incentives from the Inflation Reduction Act may mitigate some of this reduction.

Again, we would like to stress that the express objective of the ConnectedSolutions program is to reduce regional coincident peak demand, not to build out the battery landscape in Rhode Island.

Impact on Industry/Jobs

Comment: Commentors expressed concern over proposed program changes, specifically the decrease in incentive for the residential battery pathway, and how it would create a dramatic reduction in battery adoption for solar and cause a proportionately large distress for business. Residential batteries, which can currently be financed using a 0% HEAT Loan are an important lifeline that is helping keep solar and battery installers employed during the current high-interest rate environment. (2, 8)

Response: The Company values vendors and contractors who help our customers participate in our programs; we've adjusted program design to provide for a smoother transition to new incentive rates based on customer acquisition lead time.

Incentive Cap

Comment: Commentors expressed concern about implementation of a cap on incentives paid to any single battery customer. Commentors do not believe that an incentive cap is necessary and recommend that the current policy, which does not include a cap, be continued. A $1 million incentive cap is too low and will significantly limit battery development in the state. If a cap is desired, however, it should be sized to allow batteries to achieve certain economies of scale. (1,3)

Response: We hear you regarding your concerns about large battery development interest decreasing with the implementation of a $1 million participant incentive cap. However, the express objective of the ConnectedSolutions program is to reduce regional coincident peak demand. Our core design principles of ensuring diffuse and diverse load shed have led us to develop the program to be technologically agnostic and allow customers to participate with a variety of load assets. With the proposed budget, the incentive cap limits any individual participant's incentive payment to be, at maximum, about 10% of the overall

annual budget. Rhode Island Energy is not comfortable, without any sort of performance guarantee, allowing any individual customer to receive a larger portion of the budget than that.

Interconnection Process and Schedule

Comment: Commentor expressed concern about battery projects that have submitted an interconnection application but might not meet the proposed cutoff date and would be subject to newly proposed incentive caps. For these battery developers that have expended meaningful amounts of time and money to get to the point of submitting an interconnection application for a proposed battery, if subject to new rules it will likely cause queue dropout and project abandonment because projects would no longer be economic under new rules. (1)

Response: We hear you. In an attempt to balance this perspective with the objective of ConnectedSolutions, we propose to move the cutoff date from the end of the 2023 peak event season to June 1, 2024. For new battery storage systems larger than 50 kW-AC that do not yet have authority to interconnect, the customer or their vendor can choose to request a 2-year incentive lock Commitment Letter from Rhode Island Energy once an interconnection application has been accepted as complete.

The Commitment Letter will lock the incentive rate for the customer during the construction, installation, and interconnection of the battery system for up to a maximum of two years, through the 2026 peak season. Customers who receive a Commitment Letter prior to June 1st, 2024, will be eligible to receive the 2023 incentive rate through 2026.

Comment: RIE's concern that larger batteries could create disturbances on the distribution system is misplaced. All C&I batteries over 15 kW are required to go through the interconnection process and would not be permitted to interconnect unless it was determined that they would have no adverse impacts on the system or alternatively, if adverse impacts were identified, they built distribution system upgrades to mitigate these issues. Note that the cost of any such network upgrades would be borne solely by the battery developer. (1)

Response: We understand your point that measures are in place to mitigate the distribution system risk associated with large battery development. To be clear, any proposed limit on annual performance incentive payout does not change Rhode Island Energy's existing interconnection tariff. However, Rhode Island Energy is not comfortable allocating a larger portion of the budget to any single participant in the ConnectedSolutions program than the $1M cap currently proposed. ConnectedSolutions is a voluntary, pay-for-performance program, and without any sort of performance guarantee, the Company is not willing to allocate more than 10% of the overall program budget to a single participant.

Fossil Generation

Comment: Commentor expressed concern over disallowing participation by fossil generation in ConnectedSolutions. Commentor stated that it will result in higher emissions, therefore,

fossil generation should be allowed to continue to participate as long as it complies with certain environmental standards. If a decision is made to disallow participation by fossil generators, commentor recommend a phase-out period for existing generators in the Program. (1)

Response: We've been able to talk with the Rhode Island Department of Environmental Management and are satisfied that their permitting process for generators participating in demand response results in peak reduction that we can argue is environmentally responsible.

All peak demand reduction must be environmentally responsible, per Least-Cost Procurement statute and standards. Therefore, fossil-fueled backup generators are only eligible to count toward performance for the 2024-2026 ConnectedSolutions seasons if they have an active Operating Permit or Minor Source/Preconstruction Permit from the Rhode Island Department of Environmental Management (RIDEM). It is important to note that the eligibility requirements will be updated to further limit fossil fuel-based generating emissions during the 2027-2029 program years.

HEAT Loan

Comment: Commentors believe changes to the HEAT Loan eligibility on top of other programmatic changes and high interest rates will impact the ability of an average customer to afford a residential battery storage system. (2, 5)

Response: The Company's proposal is to accept HEAT Loan for all customers through May 31, 2024. But will then limit eligibility for this incentive to income-eligible customers. This helps focus funding for potential participants who need it most and reduces the amount of funding collected from all customers.

RI Renewable Energy Fund (REF), Renewable Energy Growth Program (REG), Net-Metering, and Other Programs

Comment: Commentors caution against the Company's proposed lower incentive rates and claim that customers can take advantage of other incentives is misguided. Other C&I and Residential incentive programs do not work in unison and the ConnectedSolutions incentive should be higher than those in neighboring areas in order to be economically viable. (1, 2, 4, 5, 8)

Residential battery customers can apply for the Renewable Energy Fund (REF) if they meet program guidelines. REF is only applicable to solar-plus-battery applications, so customers who install solar first and want to upgrade with a battery system later, cannot take advantage of REF. It is structured as an incentive adder, not as a stand alone incentive. Homeowners with existing solar cannot receive the energy storage incentive. Additionally, homeowners with a roof "Total Solar Resource Factor" below 80% are ineligible from participating in the REF grant program.

Residential customers pursuing the Re-Growth (REG) Program are also not eligible to receive any incentive from the REF. REG and Net Metering no-grant projects are the majority of installations in RI, making the Connected Solutions Program, effectively the only state level incentive available to the majority of battery installations. (2, 4, 5, 8)

Response: Upon further internal discussion, Rhode Island Energy agrees with some Commenter points regarding net battery export. The Company has decided to remove the discounted Daily Dispatch incentive of $185/kW for net export and instead pay the full $275/kW rate for all Daily Dispatch participation. We hear Commenter arguments that Rhode Island's ConnectedSolutions program is not an "apples to apples" comparison to neighboring demand response programs. However, Rhode Island Energy has conducted a thorough benefit-cost analysis to ensure that the incentive levels allow for all Rhode Island customers to benefit from the ConnectedSolutions program, reflected in reduced annual electric bills. The Company's analysis of net program benefits has led to the adjustment in pathway incentive level adjustments to ensure net surplus program benefits.

The existing storage programs and tariffs mentioned above have been instrumental in the early deployment of energy storage resources in Rhode Island. However, the programs operate in a patchwork. As a result of design inefficiencies, they may not incentivize the full range of net positive value that energy storage resources are capable of delivering today. This potentially leaves significant value on the table. We recognize the value added for residential customers to co-participate in various incentive and rebate programs. While each program has its own distinct rules on how each customer and solar and/or battery energy storage may participate. Where feasible, we encourage co-participation with ConnectedSolutions. While these are not outlined in the SRP Investment Proposal, Program Guides and FAQs will be released to outline and clarify commonly asked questions regarding co-participation with ConnectedSolutions.

Comment: The Company should model the program based on more representative states. The original SRP proposal was modeled on Massachusetts which mandates that only 25% of electrical consumption come from renewable sources by the year 2030. Rhode Island cannot follow their model if our goal is to achieve 100% of electrical consumption from renewable energy sources in that same time period. Vermont has a 71% goal and is still taking a more aggressive approach than Rhode Island with respect to program incentives. (5)

Response: It was not our intent to model the SRP proposal on Massachusetts. We aim to build on existing programs and lessons learned throughout the nation as energy storage technology and demand management are increasingly deployed and the market matures. We recognize each state has a unique legislative, policy, and regulatory landscape. Rhode Island set the first-in-the-nation goal to meet 100% of electricity demand with renewable energy. There is a wide variety of economic factors plus policy, programmatic, planning and equity-based actions that will support achieving this goal.

Comment: Create A Fixed Rate. Should other state programs even be considered if they introduce bias and limit ceilings of what benefits the state could receive from battery storage programs? Green Mountain Power in Vermont has created a program providing an upfront incentive with mutually beneficial risk for system performance. The grid will always need to purchase power from a source so this seems to come with little risk. If anything, the rate at which the grid purchases power is likely to increase over time and not decrease. This would create a fixed rate that can be relied upon by the grid and consumer. The benefits can clearly be seen in this article. Why shouldn't Rhode Island lead the way by creating similar creative programs to continually increase adoption and testing their own models? (5)

Response: Thank you for highlighting the Green Mountain Power program. Rhode Island Energy continuously strives to implement strategies that advance a clean energy transition while preserving affordability and reliability for our customers.

Budget

Comment: The proposed budget for C&I ConnectedSolutions will result in missed benefits for ratepayers. The annual budget should be increased to reflect battery potential in the near term and budget amounts should be more back-weighted.

The proposed budget in the Investment Proposal provides for funding of C&I ConnectedSolutions at $8 - $10 million/year for the 2024-2026 period; this covers both Daily and Targeted Dispatch and anticipates that somewhere between 5-20% is allocated to administrative expenses. Assuming that administrative costs come in at 10% of the budget in 2024, this leaves $7.2 million for Program Incentives on the low end. If Targeted Dispatch participation comes in at the Target of 45,000 kW, this would leave just $5.6 million for Daily Dispatch. CPower's pipeline of projects alone would exceed this budget. Assuming this was all used to fund batteries (which may not be the case since other types of load reducing measures can participate in Daily Dispatch) this would support roughly 18-20 MW of battery projects (depending on whether a $275/kW or $300/kW incentive is assumed). This would equate to a little over five batteries sized at 3.6 MW, or even less if a higher cap is adopted. This would leave an enormous amount of battery potential and the resulting ratepayer benefits untapped. CPower respectfully suggests that the budget be increased by at least 50% in 2025 and 2026.

Whether or not increases are made, we recommend back-weighting the budget to better match likely battery deployment timelines. We believe it is unlikely that a lot of batteries will come online in 2024 given the length of the interconnection process and the state of battery development at the moment. (1)

Response: Thank you for this added background information regarding the large battery development in Rhode Island. We appreciate that our customers are interested in making these investments. However, we don't think it is prudent to increase the program budgets

that much based on the overall bill impacts for all customers. We are actively looking for other funding sources to supplement ConnectedSolutions incentives.

Benefit Cost Analysis (BCA)

Comment: Commentor implores RIE to work with EERMC consultants, local solar and battery installers, residential battery OEMs, and other industry representatives to develop and review an updated benefit-cost analysis (BCA) using the Rhode Island Test, and then determine what the appropriate long-term customer incentive should be based on the updated BCA results. The updated BCA should consider the current and expected future benefits (e.g., emergency load reduction, frequency response distribution network management) from this important DR resource, including those that can be derived from Grid Modernization and RI PUC Docket 5000, and the impact on the local economy. For example, we believe RIE should include environmental, economic development, and reliability benefits in their BCA, which they don't appear to include in their current cursory benefit assessment.

We strongly believe the quantification of these benefits, and all other costs and benefits that could have significant impact to Rhode Islanders, need to be assessed by RIE, the EERMC, and EERMC consultants with input and review by local solar and battery installers, residential battery OEMs, and other industry experts before making any decisions related to the ConnectedSolutions Battery DR Program incentive rate or schedule. (2)

Response: Following further discussion with stakeholders, we've revised our proposal to remove the discounted incentive rate for battery export to the grid during peak events, and we have added an estimated value of energy price arbitrage, resulting in a higher proposed incentive rate for the RSB pathway in 2025 and 2026. We welcome further discussion to refine our quantification of avoided electric bill costs for future years.

Comment: Avoided Energy Cost. We want to flag that the data used from the 2021 AESC may be outdated (using 2018 data) and is worth updating to ensure a more accurate picture.

Second, batteries are key in reducing peak load. We would like to discuss further how best to incorporate that value in the proposal as well as additional clarification on the modeling used to value battery exports. Here is language from the Illinois Commission Order in Ameren IGP docket (23-0487) at p. 178 addressing this topic directly:

"Staff asserts that a VPP program seems to merely shift supply from traditional generation to battery storage and questions whether it results in any actual peak load reduction. The Commission finds that this is precisely how such a program will achieve peak load reduction; during peak hours, supply that would otherwise come from traditional generation—and possibly more expensive, peaking generation—comes in part from battery storage, thereby reducing the supply required from traditional generation during those hours." (6)

Response: We recognize using the most recent AESC values will ensure a more accurate picture. In our analysis, we are using the AESC 2021. The AESC 2024 values were released late into our process, but we plan on adding them as a sensitivity analysis.

Comment: Avoided Capacity Cost. We would like clarification on the Generational value to ensure battery exports are valued properly, regardless if they serve on-site load or not:

"Note that the Total Summer Generation value is only applicable to batteries that serve on-site load. For batteries that export to the grid during peak, the Total Summer Generation value is closer to $0/kW."

RI and MA battery behaviors are the same under ConnectedSolutions. Battery export should be also counted forward capacity credit. Behind the meter solar + battery can participate in ISO-NE FCM capacity market via On-Peak demand resource model for example. The capacity performance is measured at the battery inverter level and export is included for capacity compensation in the ISO market. (6)

Response: We understand your thought process in comparing the ConnectedSolutions program to ISO's Forward Capacity Market. However, while battery participants in ISO programs are also eligible to participate in RI Energy's ConnectedSolutions program, we do not manage their participation in the ISO programs.

Upon further review of the net export value stack, we have decided to include avoided capacity cost and avoided intrastate DRIPE. Battery participants in the Daily Dispatch pathway will receive the $275/kW incentive level for both on-site load reduction and net export.

Comment: Avoided Infrastructure Cost. We agree that avoided infrastructure costs should be included in the value stack, but would like additional clarification on how RIE plans to calculate those costs. (6)

Value of Reliability. We would like additional clarification on the calculation behind the value of reliability. We believe it should be included in the value stack. (6)

Response: Avoided distribution infrastructure cost is set at $120/kW in 2024 based on the average of the past five years of avoided costs (2020-2024), each determined using the method recommended by the 2021 AESC Study, and the general increasing trend in avoided distribution infrastructure costs ($80/kW in 2020, $174/kW in 2024).

The Company did not include the benefits value of reliability. Rhode Island Energy uses willingness to pay concept for determining value of peak demand reduction. RIE's willingness to pay for a unit of peak demand reduction is equivalent to the cost our customers would otherwise pay for us to serve that unit of demand during peak. These values are specifically limited to costs that would materialize on customer electric bills: energy costs and associated demand reduction induced price effects (DRIPE), energy

price arbitrage, capacity costs and associated intrastate DRIPE, Regional Network Service (RNS) charges, transmission infrastructure cost, and distribution infrastructure costs.

Comment: Regional Network Service (RNS) Cost. Would like to discuss in more depth the difference in value between "on-site batteries for load shed only" vs "energy exports." (6)

Response: Regional Network Service (RNS) cost savings are equally accounted in the benefits value stack for "on-site batteries for load shed only" as well as for "energy exports.

Comment: The SRP Investment Proposal recommends reducing the C&I Daily Dispatch incentive rate from $300/kW to $275/kW to match the incentive level in neighboring areas. In arriving at this rate, we understand that RIE relied on the results of an analysis that indicates savings to ratepayers from net export is worth roughly $70/kW less than savings from load reduction, because net export does not produce capacity cost savings. Commenter disagrees with this conclusion.

Net export of energy at a customer meter reduces load at the substation and therefore produces the same savings in capacity costs as load reduction at the customer meter. Our understanding of the analysis that RIE relied on to develop the $275/kW incentive rate is that it did not assign any of the benefits of demand response in the capacity market to energy exported at the customer meter. As noted above, we believe this is not an accurate representation of the benefits from net exported energy at a retail customer meter.

Three "buckets" of capacity market savings accrue from load reductions: 1) individual customers reduce their ICAP tag when they reduce their contribution to the single peak hour in the year (meaning they lower their individual capacity costs), 2) the capacity costs allocated to the capacity zone are lowered because the zone's contribution to the annual peak hour is reduced, and 3) capacity requirements going forward (for roughly the next 15 years) are lower because the historical peak loads that ISO-NE bases its calculations on are lower.

In summary, net export at a customer meter during the system peak will reduce customer ICAP tags, the allocation of capacity costs to the capacity zones, and capacity requirements. Note that the effect of lower peak demand in a single year has a long-lived effect on capacity requirements because ISO-NE uses a rolling 15-year lookback of historical loads to develop its load forecast used in calculating capacity requirements. Given this, CPower believes that RIE's consultant should revise its analysis to properly reflect the capacity cost savings created by net export at a customer's meter. These savings are the same as those created by load reduction at the customer meter. Making this revision should give RIE the latitude to leave the incentive rate unchanged at

$300/kW because the benefits create by both net export and load reduction are expected to exceed this value by a good margin. (1)

Response: We appreciate your research and insight into the value of net export. We would like to clarify that the incentive level decrease to $275/kW for Daily Dispatch was not a result of the conclusion of a reduced savings value for net export, but rather a result of the avoided cost associated with any 1kW of peak load shed. Upon further analysis of the avoided capacity costs due to net export, we agree with your arguments that these avoided costs are not negligible for battery export surplus of on-site load. As a result, Rhode Island Energy has decided to remove the discounted incentive level of $185/kW for net export and instead offer the full $275/kW for all Daily Dispatch average load shed achieved, including net export. However, we are not comfortable offering an incentive level of $300/kW as this would reduce net surplus savings and in turn, reduce customer bill savings as well.

Other Comment: Provide clarification on how the standards required in "system reliability procurement" benefit cost analysis interact with this 2017 docket: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4600-WGReport_4-5-17.pdf

Including the special value of GHG emissions reductions (included in Massachusetts), and other societal / non-energy values.

Avoided non-electricity fuel charges: Deliverable fuel benefits (NG & other fuels) is the consumption of these other fuels reduced by use of this program, and has been included in other programs (MA).

Water, sewage, and disposal benefits (included in MA ConnectedSolutions) (6)

Response: The LCP Standards directly reference the RI Framework developed in Docket 4600 in its guidance on determining compliance with the standards of cost-effectiveness and lower than the cost of the best alternative utility reliability procurement. Our assessment shows that our proposed program design meets both of these standards.

Comment: Customers should have the ability to obtain incentives for larger batteries (>10 MW) via a separate procurement track.

Capping the incentive at $3 million will leave larger customers without a viable avenue for developing onsite batteries; this can be addressed by providing batteries that are larger than 10 MW with a separate track for obtaining incentives outside of the ConnectedSolutions Program. CPower will provide detailed comments on this concept in early 2024, but we lay out some basic ideas below.

Under this separate track, the "procurement track", project sponsors would apply for an incentive at a TDB rate, locked in for 10 years. During the 10-year lock-in period,

projects would be dispatched during Daily Dispatch events and would be expected to perform at 95% of their capacity value or better. Performance less than 95% of this value would result in penalties.

The initial application under the procurement track would be submitted to RIE for review and feedback. Once the application is complete, RIE would perform a benefit-cost assessment of the project (or the project sponsor could if the required tools were provided) and then the results of the analysis, along with the proposed incentive offer, would be filed with the PUC for approval.

This process would be similar to the process developed in 2018 to review incentives provided to Combined Heat and Power ("CHP") projects. Under that process, CHP projects that are cost-effective and create no capacity or reliability concerns can, subject to PUC authorization, obtain incentive packages that are locked in for 10 years, as long as these incentives do not exceed 70% of the total project cost. (1)

Response: This might be possible but would be outside of ConnectedSolutions. The potential for this "one off" procurement track for large C&I batteries could be raised in the broader SRP context. The CHP process was mandated by Rhode Island Statute.

CPower Comments
CPower, a curtailment service provider, submitted written comments to Rhode Island Energy and the Council on October 19, 2023 and December 20, 2023.

CPower-1
CPower supports the draft SRP's plan to preserve and expand the benefits provided by demand response in the ConnectedSolutions program, but believes some plan modifications, discussed herein, are needed. As noted in the SRP, the ConnectedSolutions Program has produced meaningful peak load reductions that have resulted in significant savings to Rhode Island ratepayers since inception in 2019. CPower believes the Program has potential to provide even greater savings to customers through increased participation by batteries in Daily Dispatch.

CPower-2
Rhode Island Energy ("RIE") proposes to implement a cap on the incentive paid to any single battery customer. The impetus for this change appears to be: 1) concern that the reliability of response could suffer if any single resource makes up a significant portion of the Program capacity, 2) an interest in ensuring that the Program benefits are allocated equitably across a large number of customers, and 3) fear that large batteries could create disturbances on the distribution system.

CPower feels the concerns driving the cap proposal may be the result of misunderstandings. We do not believe that an incentive cap is necessary and recommend that the current policy, which does not include a cap, be continued. If a cap is desired, however, it should be sized to allow batteries to achieve certain economies of scale. We provide more detail on this topic below.

CPower-3
RIE suggests that because the Program is voluntary, it cannot count on consistent performance from participants and therefore it should not allow a single participant to make up too large of a percentage of its target load reduction 1. We believe that RIE is conflating uneven response from load curtailment with expectations for battery performance. Load curtailment customers generally interrupt some type of business process to provide a load reduction, and therefore may, at times, choose a higher value activity over load curtailment. In contrast, a customer with a battery does not need to interrupt a business process to provide a load reduction, realizes cost savings when it responds to a ConnectedSolutions call, and has no higher value alternative to performing in ConnectedSolutions.

The battery owner has no higher value use than ConnectedSolutions because it needs Program revenues to recoup its investment in the battery. Notably, C&I batteries are increasingly owned and financed by a third-party investor who funds the battery with the expectation that the majority of the return on capital invested will come from revenues generated from the ConnectedSolutions Program, while the customer realizes on-bill savings and resilience. In short, ConnectedSolutions revenues are foundational to the investment; without them, the project is not economically viable. As such, the investor has a strong incentive to ensure the consistent and reliable performance of the battery in response to ConnectedSolutions dispatches. Without this performance, they will not earn a return on their investment. As a result, performance expectations are typically included in the contractual arrangements for the battery and ConnectedSolutions performance is the top priority.

While it is certainly possible that a battery could suffer a forced outage that prevents it from performing, this isn't a likely scenario for a brand new battery and any such outages would be short-lived since the project owners and managers are both motivated and obligated to drive high battery asset availability in order to realize the revenues necessary to recoup the battery's invested capital.

Given the foregoing, CPower does not believe that providing incentives for relatively large batteries will adversely affect the reliability of response.

If concerns remain on this front, CPower suggests that RIE collect data from batteries in the Program for a year or two to assess battery performance relative to Program enrollment values. CPower believes that the results will show that battery performance is near perfect, however, if this is not the case, "course corrections" can be made to ensure achievement of the Program goals.

CPower-4
RIE suggests that an equitable allocation of benefits, consistent with Least Cost Procurement (LCP) standards, requires that Program incentives be dispersed to a relatively broad swath of participants. If applied to batteries in isolation, this objective probably isn't achievable. It would require many small batteries to be developed at sites across the state. There are a couple of problems with this concept. The sheer volume of small batteries that would be needed to meet Program goals makes this scenario unrealistic in the near to medium term. More importantly though, small batteries cannot achieve economies of scale that make them financially viable in most cases. Consequently, we're not likely to see a lot of small batteries being developed unless more lucrative incentives are provided or the underlying cost drivers change.

The more economic way to achieve the target load reduction is with relatively larger batteries (2 MW – 5 MW). Importantly, while the program incentives paid to these batteries would not be shared among a broad swath of participants, the benefits would be. The benefits of the peak load reductions produced by batteries in the Program – specifically lower energy costs and reduced emissions - would be enjoyed by all ratepayers in Rhode Island. CPower believes this is consistent with the equitable allocation of benefits envisioned in the LCP standards.

CPower-5
RIE's concern that larger batteries could create disturbances on the distribution system is misplaced. All C&I batteries over 15 kW are required to go through the interconnection process and would not be permitted to interconnect unless it was determined that they would have no adverse impacts on the system or alternatively, if adverse impacts were identified, they built distribution system upgrades to mitigate these issues. Note that the cost of any such network upgrades would be borne solely by the battery developer.

CPower-6
CPower does not believe it is necessary to cap the incentive paid to an individual battery. If a cap is desired nonetheless, it must be structured so that batteries can still achieve economies of scale and produce resilience benefits for the hosting customer.

As discussed above, it is difficult to make a battery "pencil" without being able to achieve some economies of scale. Even with these economies of scale, customer-sited batteries need the incentive from ConnectedSolutions (or a similar program) in order to be economically viable.

With this in mind, CPower recommends that the program continue without a cap on the incentive for batteries. Any cap will inevitably reduce the pool of potentially viable battery projects, making it more difficult to reach load reduction targets and provide benefits to ratepayers. Large customers in particular, who tend to be prime candidates for on-site batteries, will not be interested in developing batteries that are sized smaller than their peak load because such batteries do not deliver meaningful resilience.

If RIE continues to feel a cap is desirable, CPower suggests capping the annual incentive at the amount that could be earned by a battery sized at the higher of 4.99 MW or the customer's peak load. 4.99 MW is a natural cutoff point because batteries that are 5 MW or larger are required to conduct an ISO-NE transmission study as part of the interconnection process. Allowing the cap to go above 4.99 MW (up to the customer's peak load) will make battery development attractive for larger customers. Further, this level of incentive will be large enough to attract batteries that can achieve some economies of scale and will position the state to attract a good number of batteries but would prevent it from meeting its goals entirely with one or two large resources.

CPower Recommendation: CPower's preference is to continue the Program without an incentive cap, but if a cap is desired: cap the annual incentive per battery based on the incentive that would be earned by a battery sized at the higher of 4,990 kW or the host customer's peak load. Peak load should be established as the single hour peak gross demand2 (kW) over the three years prior to submission of the interconnection application.

CPower-7
Batteries that have submitted an interconnection application as of the date that the DPU issues an order on the 2024-2026 SRP should not be subject to any new incentive cap that is adopted.

Battery developers must expend a meaningful amount of time and money to get to the point of submitting an interconnection application for a proposed battery. These costs include not only the cost of the interconnection application itself, but also the cost of preliminary engineering and permitting work. As such, any battery that has an interconnection application on file as of the date of a DPU Order on the 2024-2026 SRP should not be subject to the new rules in that Order. To do otherwise will likely cause queue dropout and project abandonment because projects that were economic under the current rules may no longer be economic under the new rules. Developers that are forced to abandon projects mid-stream due to deteriorated economics will be left with unrecoverable costs and a heightened sense of regulatory risk. This will dampen interest in bringing batteries to the Program, ultimately hampering the ability to meet the Program goals. This type of outcome can be avoided, however, by grandfathering projects that have submitted an interconnection application as of the date on which new rules are approved by the DPU.

CPower Recommendation: Apply any new incentive cap only to batteries that submit an interconnection application after the date of a DPU Order on the 2024-26 SRP.

CPower-8
New batteries enrolling in the Program should have the ability to lock in the incentive rate and performance calculation methodology for multiple years.

Developing a battery is a costly and labor-intensive undertaking. As such, customers and investors are generally unwilling to invest in a battery unless they have a reasonable amount of certainty that they will be able to recoup their investment. Providing a multi-year lock of the incentive rate and the performance calculation methodology goes a long way in providing this assurance. This is not a novel concept. Existing ConnectedSolutions programs in other states provide a five-year rate lock to batteries, and the Connecticut Energy Storage Solutions Program provides a 10-year rate lock.

Note that a lock of the incentive rate alone is insufficient to give project sponsors the revenue certainty they need because a change to the performance measurement methodology could result in a significant decrease in their revenues during the lock-in period even though the incentive rate is locked in. CPower recommends a 10-year lock-in period, consistent with what the Connecticut Energy Storage Solutions Program offers. If RIE prefers a shorter lock-in period, it should offer no less than a five-year lock-in period.

CPower also recommends that RIE provide “commitment letters” to battery project sponsors upon request. A commitment letter is a letter documenting the rate and performance methodology lock-in and can be requested by a project sponsor once it has submitted an interconnection application. The letter locks in the then-prevailing rate and performance calculation methodology for the chosen lock-in duration starting on the earlier of the project’s commercial operation date or two years after the letter is issued. The MassSave ConnectedSolutions Program provides this option to project sponsors. It gives investors some certainty on expected revenue streams before they fund a System Impact Study and equipment purchases. Both of these milestones require significant financial outlays that investors generally will not agree to without reasonable assurance on the revenue streams that will go toward recouping their investment.

CPower Recommendation: Provide commitment letter upon request for batteries that have submitted an Interconnection Application. The commitment letter will lock in the then-prevailing incentive rate and performance calculation methodology for at least five years (preferably 10 years) starting on the earlier of the project’s commercial operation date or two years after the letter is issued.

CPower-9
Disallowing participation by fossil generation in ConnectedSolutions will result in higher emissions, therefore, fossil generation should be allowed to continue to participate as long as it complies with certain environmental standards.

RIE is contemplating eliminating fossil generation from the ConnectedSolutions Program entirely. CPower fully supports the goal of reducing carbon emissions but believes this change would undermine that goal.

Without the incentive provided by the Connected Solutions programs, many C&I customers will choose less environmentally friendly ways to meet their back-up generation needs. Generators in the Connected Solutions program meet federal EPA non-emergency emissions standards and are permitted by the Rhode

Island Department of Environmental Management (RIDEM) to operate for demand management purposes.

A number of CPower's C&I customers have made investments in recent years to retrofit existing on-site generation or purchase new back-up generation. These customers chose the more expensive, environmentally friendly options in order to qualify for demand response participation, which provides them with an additional revenue stream. Without the promise of that revenue stream, they would have purchased the less expensive, less environmentally friendly option or would have forgone retrofitting. This illustrates one reason why the plan to eliminate generators from the ConnectedSolutions program is not likely to result in lower emissions. C&I customers will continue to maintain back-up generation, but without the incentive to meet stricter environmental standards, they will almost certainly choose less expensive and less environmentally friendly options. This will result in higher emissions when these generators are used to meet resiliency, maintenance, testing, and other needs.

Additionally, eliminating fossil generation from the program will reduce peak load reductions provided by ConnectedSolutions, reducing benefits realized by ratepayers (including emissions reductions) from the program.

CPower Recommendation: Continue to allow generators that are permitted by the Rhode Island Department of Environmental Management (RIDEM) and meet federal EPA non-emergency emissions standards to participate in ConnectedSolutions.

If a decision is made to disallow participation by fossil fuel generation in ConnectedSolutions, a transition period should be implemented to phase out participation for existing generators in the Program. Customers with existing generation in the Program made investments in cleaner technology based on the understanding that they would earn revenues in the ConnectedSolutions Program to offset those costs. As such, it would be inequitable to discontinue their participation abruptly.

CPower Recommendation: If a decision is made to disallow participation by fossil generators, provide a phase-out period for existing generators in the Program.

CPower-10
Incentive Cap for Batteries

The SRP Investment Proposal recommends capping the incentive that can be earned in the C&I ConnectedSolutions Program at $1 million per participant per year. The impetus is, in part, a belief that more "diffuse" participation will result in greater reliability of response.

A $1 million incentive cap is too low and will significantly limit battery development in the state.

Any cap on the incentive that can be received by a participant will act as an effective cap on battery size because batteries are generally not economic to build without incentives that support their full capacity value. A $1 million cap translates to a cap on battery size of roughly 3.6 MW, assuming the customer is not also providing load curtailment in the Targeted Dispatch Program. If the customer is already providing load curtailment, the effective cap would be even lower; this case is discussed in more detail in the next section.

An effective battery cap of 3.6 MW will significantly shrink the pool of customers who are interested in installing an on-site battery. Customers generally install batteries for two reasons: 1) they provide resiliency, and 2) they can help them reduce their energy bill. A 3.6 MW battery, however, can provide meaningful resilience and bill reduction only if the customer's peak load is lower than 3.6 MW. As such, we don't expect customers with peak loads over ~3 MW to have a lot of interest in installing a battery if the incentive is capped at $1 million. In CPower's experience, however, it is large customers – customers with loads greater than 3 MW - who are most interested in installing on-site batteries. Of the batteries in CPower's pipeline, roughly 80% are sized larger than 3.6 MW and likely will not move forward if the proposed incentive cap is adopted without any type of grandfathering provision.

With regard to smaller C&I customers and smaller batteries, we don't expect C&I customers with lower peak loads (less than ~2 MW) to have much interest in installing batteries because smaller batteries simply don't have the economies of scale that make these projects financially viable. A higher incentive rate would be needed to encourage battery adoption for smaller C&I customers.

In short, a cap of $1 million will encourage battery adoption in only a small segment of potential battery customers; it completely shuts out larger C&I customers who are likely the best candidates for on-site batteries because of the economies of scale they can achieve and the higher benefit-to-cost ratios they produce.

CPower-11
Any incentive cap should be applied per customer measure, rather than per customer. Applying the cap per customer is likely to result in the loss of load curtailment measures from the Program.

Customers in ConnectedSolutions can participate in both Targeted Dispatch and Daily Dispatch with different measures. For example, a manufacturing facility might provide load curtailment in Targeted Dispatch by interrupting a manufacturing process when dispatched. They might later decide to install an on-site battery and participate in Daily Dispatch with that battery. If this customer's total incentive is capped at $1 million, the cap available to the battery would be $1 million minus the incentive earned through Targeted Dispatch. However, the more likely course of action in this scenario is that the customer would discontinue load curtailment activities in Targeted Dispatch in order to maximize the incentive that can be received by the battery. This would not be an optimal outcome for ratepayers, since they wouldn't be able to realize the full benefit of this customer's load reduction capabilities. As such, CPower recommends that any incentive cap be applied per measure rather than per customer.

CPower-12
CPower feels a cap is unnecessary but if a cap must be implemented, we recommend a cap of $3 million per customer measure per year.

A cap of $3 million per customer measure would allow on-site batteries sized up to 10 MW to be developed in the state with an incentive rate of $300/kW. (CPower's views on the incentive rate are discussed in Section 2 below). A cutoff point at $3 million makes sense because incentives sized larger than this would require authorization from the PUC. Per the Annual Energy Efficiency Plan for 2018 approved by the PUC, "the Company will file a written notification with the PUC of any energy efficiency incentive annual offer in excess of $3 million. The project, the incentive, and any other related

proposals will be authorized to proceed after thirty days from the notice filing unless the PUC suspends the filing and/or issues an order within such 30-day period to extend the time for purposes of further review". [emphasis added].

Importantly, a cap of $3 million (effectively 10 MW) would enable a much larger set of customers to develop batteries and would ensure that the batteries that are developed can achieve reasonable economies of scale, making development more likely to happen and resulting in higher benefit-cost ratios.

As CPower noted in its comments on the SRP, we believe the concerns driving the cap proposal may be the result of misunderstandings. Diffuse participation will not lead to greater reliability of response among battery customers because, unlike a load curtailment customer, a battery has no higher value alternative to responding to ConnectedSolutions dispatches. Please see our November 16, 2023 comments on the SRP for more detail on this topic.

CPower-13
Customers should have the ability to obtain incentives for larger batteries (>10 MW) via a separate procurement track.

Capping the incentive at $3 million will leave larger customers without a viable avenue for developing onsite batteries; this can be addressed by providing batteries that are larger than 10 MW with a separate track for obtaining incentives outside of the ConnectedSolutions Program. CPower will provide detailed comments on this concept in early 2024, but we lay out some basic ideas below.

Under this separate track, the "procurement track", project sponsors would apply for an incentive at a TDB rate, locked in for 10 years. During the 10-year lock-in period, projects would be dispatched during Daily Dispatch events and would be expected to perform at 95% of their capacity value or better. Performance less than 95% of this value would result in penalties.

The initial application under the procurement track would be submitted to RIE for review and feedback. Once the application is complete, RIE would perform a benefit-cost assessment of the project (or the project sponsor could if the required tools were provided) and then the results of the analysis, along with the proposed incentive offer, would be filed with the PUC for approval.

This process would be similar to the process developed in 2018 to review incentives provided to Combined Heat and Power ("CHP") projects. Under that process, CHP projects that are cost-effective and create no capacity or reliability concerns can, subject to PUC authorization, obtain incentive packages that are locked in for 10 years, as long as these incentives do not exceed 70% of the total project cost.

CPower-14
Batteries that have submitted an interconnection application as of the date that the DPU issues an order on the 2024-2026 SRP should be grandfathered under the current rules.

It is crucial that the Investment Proposal provide for grandfathering of batteries that have already entered the interconnection queue. Project Sponsors for these batteries have already spent significant time and money to get their projects to this stage of development. Their costs include not only the cost of the interconnection application itself, but also the cost of preliminary engineering and permitting work.

Project Sponsors anticipated recovering these costs through program incentives. If instead these batteries are subject to a $1 million incentive cap, many will become unviable and drop out of the interconnection queue, leaving project sponsors with unrecoverable costs. This will chill interest in developing C&I batteries in the state because developers will no longer have confidence in the stability of the rules, and therefore will view Rhode Island as a risky investment environment. We have already seen signs of this happening in Massachusetts, where an incentive cap was implemented with little notice and effective grandfathering provisions were not adopted.

To avoid this outcome, CPower recommends that any battery that has an interconnection application on file as of the date of a PUC Order on the SRP Investment Proposal not be subject to the new incentive capping rules. To do otherwise will significantly dampen interest in C&I battery development in Rhode Island.

CPower-15
The SRP Investment Proposal recommends reducing the C&I Daily Dispatch incentive rate from $300/kW to $275/kW to match the incentive level in neighboring areas. In arriving at this rate, we understand that RIE relied on the results of an analysis that indicates savings to ratepayers from net export is worth roughly $70/kW less than savings from load reduction, because net export does not produce capacity cost savings. CPower disagrees with this conclusion.

Net export of energy at a customer meter reduces load at the substation and therefore produces the same savings in capacity costs as load reduction at the customer meter.

Our understanding of the analysis that RIE relied on to develop the $275/kW incentive rate is that it did not assign any of the benefits of demand response in the capacity market to energy exported at the customer meter. As noted above, we believe this is not an accurate representation of the benefits from net exported energy at a retail customer meter.

Three “buckets” of capacity market savings accrue from load reductions: 1) individual customers reduce their ICAP tag when they reduce their contribution to the single peak hour in the year (meaning they lower their individual capacity costs), 2) the capacity costs allocated to the capacity zone are lowered because the zone’s contribution to the annual peak hour is reduced, and 3) capacity requirements going forward (for roughly the next 15 years) are lower because the historical peak loads that ISO-NE bases its calculations on are lower. Each one of these value streams is discussed in more detail below.

Customer ICAP Tag Reductions

By way of background, each Load Serving Entity (LSE) in New England is allocated a share of zonal capacity obligations based on their contribution to the annual system peak hour in the year prior to the commitment period. Their capacity costs are then calculated based on their allocated capacity obligation.

An LSE’s contribution to the annual system peak hour is equal to the sum of their customers’ contributions. Medium and large C&I customers generally arrange with their LSE for the direct pass-through of capacity charges, allowing them to reduce their capacity charges by reducing their contribution to the annual system peak load.

Utilities are responsible for calculating each customer's contribution to the system peak, known as their "ICAP tag". These tags are calculated based on interval meter data where available, and load profiles, where interval meter data is unavailable. In both cases, however, adjustments are made to the ICAP tag for losses on the transmission and distribution system and unaccounted for energy and losses. These adjustments are made to ensure that the sum of customer ICAP tags is equal to the metered demand for the metering domain during the peak hour. Importantly, net export at a customer meter would be factored into ICAP tags as part of unaccounted for energy and losses.

National Grid's practices related to ICAP tags are laid out in a document posted on their website; we assume RIE has adopted similar practices to ensure that the sum of customer ICAP tags is equal to the metered demand for the metering domain during the peak hour.

As explained in the National Grid document, "A number of adjustments are made to the individual customer peak contributions so that the total is reconciled to National Grid's total demands (by Load Zone) at the time of the ISO-NE peak." More specifically they show that for both profiled and non-profiled customers, the initial determination of the customer's contribution to the peak is adjusted for a "Loss Factor" and an "NLD Adjustment Factor". The latter is defined as shown below.

NLD Adjustment Factor = Unaccounted for energy and losses factor. It is used to reconcile the estimates to National Grid's total demands by Load Zone at the time of the ISO-NE peak (i.e. target/actual).

In other words, net export would show up for in the NLD Adjustment Factor and the resulting load reduction would be spread across all customers' ICAP tags in the metering domain. As such, net export does reduce customer ICAP tags, but the customer producing the net export sees only a fraction of this benefit.

Reduction in Zonal Capacity Obligation

By way of background, each Capacity Zone is allocated a share of the capacity procured for the system based on its contribution to the system peak hour in the year prior to the commitment period. The zone's costs are then calculated based on this share. This allocation of capacity to each zone is called "Zonal Capacity Obligation or "ZCO". A zone's contribution to the system peak hour is the sum of all load serving entities' contributions (ICAP tags) in the zone.

Because net export is factored into ICAP tags (as described in the preceding section), and ICAP tags are used to determine a capacity zone's share of total capacity procured, net export reduces the capacity costs allocated to a Capacity Zone in the same way that load reduction at the customer meter does.

Reduction in Capacity Requirements

ISO-NE calculates capacity requirements for the system and constrained capacity zones on an annual basis according to the provisions laid out in Section III.12 of Market 9 Rule 1.

As explained in Section III.12.8, one of the inputs into the calculation of capacity requirements is the load forecast. In fact, the load forecast is one of the biggest drivers of recent changes in capacity requirements.

A forecast for higher peak loads produces higher capacity requirements/higher capacity costs, and conversely, a forecast for lower peak loads produces lower capacity requirements/lower capacity costs.

The main drivers affecting forecast loads are historical loads, weather, and the economic outlook. With regard to historical loads, ISO-NE uses a rolling 15-year window that includes the last historical year. Historical load is determined by metering, specifically, it is the net generation, plus net interchange across external tie lines, less energy required for storage at energy storage facilities (energy storage in this context is front of the meter storage; generation in this context is Generation that is reported to ISO-NE). In short, net export at a customer meter would reduce the net Generation needed to supply the metering domain and therefore would result in lower peak demand at the zonal level, which would result in lower capacity requirements and thus lower capacity costs.

In summary, net export at a customer meter during the system peak will reduce customer ICAP tags, the allocation of capacity costs to the capacity zones, and capacity requirements. Note that the effect of lower peak demand in a single year has a long-lived effect on capacity requirements because ISO-NE uses a rolling 15-year lookback of historical loads to develop its load forecast used in calculating capacity requirements.

Given this, CPower believes that RIE's consultant should revise its analysis to properly reflect the capacity cost savings created by net export at a customer's meter. These savings are the same as those created by load reduction at the customer meter. Making this revision should give RIE the latitude to leave the incentive rate unchanged at $300/kW because the benefits create by both net export and load reduction are expected to exceed this value by a good margin.

CPower-16
Comparing the RIE Incentive Rate to that in neighboring areas is not an "apples to apples" comparison.

Batteries in Massachusetts can earn additional revenues on top of their ConnectedSolutions incentives by selling Clean Peak Energy Certificates, therefore they do not need as large of an incentive from ConnectedSolutions as batteries in states without additional revenue streams (such as Rhode Island). Batteries in Connecticut earn an upfront incentive in addition to the performance incentive in the Energy Storage Solutions Program and incentive rates are locked in for 10 years. As a result, batteries in Connecticut also do not need as large of a performance incentive as batteries in states without upfront incentives or 10-year certainty.

In contrast, the only incentive that on-site C&I batteries in Rhode Island are eligible for is the ConnectedSolutions performance incentive and while this incentive is purportedly locked in for five years, even this is not guaranteed. Draft SRP Investment Proposal, p. 23 states, "…Rhode Island Energy plans to honor the five-year rate lock for Daily Dispatch customers who enrolled battery assets during or prior to the 2023 season through 2026. Also, please note that the prior five-year incentive lock represents Rhode Island Energy's intentions; it is not a guarantee of incentive levels."

The incentive rate for C&I batteries in Daily Dispatch should be left at $300/kW; reducing the rate below this will make it more difficult to attract batteries to the Program.

If RIE feels it is important to provide lower compensation for net export, then the lower rate of $275/kW should apply only to net export.

Due to the differences discussed above, batteries in Rhode Island need a higher performance incentive than those in neighboring areas in order to be economically viable. More specifically, batteries in Rhode Island do not have access to revenue sources other than ConnectedSolutions and the regulatory risk is also higher in Rhode Island because rates are locked for only five years, and that rate lock is not guaranteed. As such, reducing the incentive rate available to on-site C&I batteries in Rhode Island would be a step in the wrong direction and would only shrink the pool of customers who might be interested in installing an on-site batteries. Additionally, as discussed in the preceding section, the rationale for the lower rate (based on lower benefits from net export) is faulty. Given this, CPower recommends that the $300/kW incentive rate for C&I Daly Dispatch batteries be left unchanged. However, if RIE is not comfortable providing a $300/kW incentive to net export, we recommend lowering the rate to $275/kW only for the energy that is exported at the customer meter.

CPower-17
The importance of a Multi-Year Revenue Lock

Both the incentive rate and the methodology for calculating performance should be locked in for at least five years, but preferably 10 years. A longer lock-in period would allow RIE to pay a lower incentive rate on the back end.

Exceptions to the “two-year rate lock hold” should be provided for projects that are unable to come online within two years due to interconnection delays.

CPower is very appreciative of the rate lock provisions included in the draft SRP Investment Proposal but is concerned that this provision does not go far enough to provide revenue certainty to those investing in on-site batteries. The proposed provision provides for a 5-year rate lock, that can be secured up to two years in advance of a project reaching commercial operation.

Our concerns regarding this provision include the following: 1) it explicitly states that the rate lock is not guaranteed, 2) although the rate is locked (albeit without a guarantee), there is no lock on the methodology used to calculate the performance upon which the rate is paid, and 3) the rate lock is “held” for up to two years but given interconnection process challenges – which developers have no control over – it is unclear whether two years is enough time for a project to get through the interconnection process and reach commercial operation.

While CPower understands that events beyond RIE’s control could jeopardize the rate lock, it urges RIE and the EERMC to emphasize the importance of this rate lock to the PUC. If events did occur that resulted in RIE being unable to honor the rate lock, this would significantly chill interest in battery development, since investors would have no confidence in earning incentives for even the five-year rate lock period. Batteries are sizable investments for C&I customers; as a result, most will not consider installing a battery without retail incentives that help defray the cost and most require financing from a lender. If the retail incentive cannot be counted on for even a five-year period, the investment becomes too risky for both customers and lenders.

While a rate lock is both welcome and necessary, failing to lock in the way performance is calculated means that a battery customer is still exposed to a fair amount of uncertainty regarding their future revenue stream. If the method for assessing the performance upon which a battery is paid were to change (e.g., a new incentive cap was implemented), this could materially reduce the revenues available to that battery from ConnectedSolutions. As noted above, developing a battery is an expensive endeavor that customers and lenders will support only if there is some degree of certainty on the revenue stream available to recoup the costs and service the debt. As such, the five-year lock should freeze both the incentive rate and the performance calculation for the rate lock period.

Additionally, consideration should be given to extending the rate lock past five years. Because there is no visibility on what the incentive will be after the rate lock expires or even if the program will continue to exist, most investors will assume a lower incentive after year 5. As a result, they need a higher incentive rate with a five-year rate lock than a 10-year rate lock. As such, consideration should be given to extending the rate lock past five years; this could allow RIE to offer a lower incentive rate in the second half of the lock-in period; providing savings to ratepayers and allowing the Program to accommodate a greater number of batteries.

Finally, RIE should allow a rate lock to take effect later than the two-year mark if the project has been unable to reach commercial operation due to interconnection delays.

CPower-18
C&I ConnectedSolutions Budget

The proposed budget of $8 - $10 million/year for C&I ConnectedSolutions will result in missed benefits for ratepayers.

The annual budget should be increased to reflect battery potential in the near term and budget amounts should be more back-weighted.

The proposed budget in the Investment Proposal provides for funding of C&I ConnectedSolutions at $8 - $10 million/year for the 2024-2026 period; this covers both Daily and Targeted Dispatch and anticipates that somewhere between 5-20% is allocated to administrative expenses. Assuming that administrative costs come in at 10% of the budget in 2024, this leaves $7.2 million for Program Incentives on the low end. If Targeted Dispatch participation comes in at the Target of 45,000 kW, this would leave just $5.6 million for Daily Dispatch. CPower's pipeline of projects alone would exceed this budget. Assuming this was all used to fund batteries (which may not be the case since other types of load reducing measures can participate in Daily Dispatch) this would support roughly 18-20 MW of battery projects (depending on whether a $275/kW or $300/kW incentive is assumed). This would equate to a little over five batteries sized at 3.6 MW, or even less if a higher cap is adopted. This would leave an enormous amount of battery potential and the resulting ratepayer benefits untapped. CPower respectfully suggests that the budget be increased by at least 50% in 2025 and 2026.

Whether or not increases are made, we recommend back-weighting the budget to better match likely battery deployment timelines. We believe it is unlikely that a lot of batteries will come online in 2024 given the length of the interconnection process and the state of battery development at the moment.

CPower appreciates the opportunity to provide these comments. We forward to working with the EERMC and RIE to enable the continued success of the ConnectedSolutions Program in Rhode Island.

Enphase Energy Comments
Enphase Energy, a solar and battery storage company, submitted written comments to the Council on January 24, 2024.

Enphase Energy-1
Lower Incentives Equals Lower Participation

Data from Enphase battery installations and program participation in both Massachusetts and Rhode Island show us that, in fact, participants are not equally willing to reduce peak demand for less incentive. The current ConnectedSolutions Battery DR Program in Rhode Island has been a great success story that demonstrates the scalability and value of grid services programs and Virtual Power Plants (VPPs). The slightly higher incentive in Rhode Island compared to Massachusetts has resulted in much higher battery deployment and program participation per capita in Rhode Island, and therefore, a greater reduction in supply costs for all ratepayers. Specifically, by providing a 45% higher incentive rate (i.e., $400 compared to $275/kW-yr), Enphase customers have enrolled well over four times more batteries per capita in the Rhode Island ConnectedSolutions Battery DR program than the Massachusetts program (i.e., 0.41 compared to 1.91 Wh/person), while solar installed capacities per capita are nearly identical between the states (i.e., 56.7 compared to 56.9 W/person).

Enphase Energy-2
REF Is Not Sufficient

Historically, it is our understanding that the higher Rhode Island ConnectedSolutions Battery DR Program incentive rate compared to Massachusetts was justified in part because Massachusetts had additional battery incentive programs, like the SMART Energy Storage Adder, which provided residential solar-plus-battery customers hundreds of dollars of additional incentives on top of ConnectedSolutions incentives. For example, even today (Tranche 10), the Massachusetts SMART Energy Storage Adder program typically results in an additional battery customer incentive of around $500 per year for 10 years (i.e., $5,000 lifetime incentive) assuming 9 kW solar and 15 kWh of installed battery capacity. However, Rhode Island customers cannot participate in either SMART.

Instead, Rhode Island battery customers can apply for the Renewable Energy Fund (REF) program, which provides a one-time $2,000 upfront incentive for batteries paired with solar, which is a much lower lifetime incentive than the current Massachusetts battery incentive programs. In addition, the REF is limited to roofs with a TSRF over 80% and the grant only opens during certain periods of the year - delaying installations - and the process to obtain the funds can be difficult. Also, REF is only applicable to solar-plus-battery applications, so customers who install solar first and want to upgrade with a battery system later, cannot take advantage of REF. As an example of the challenges installers face using this program, in 2022, of the 37 battery sites installed by one installer, 10 customers were adding batteries to existing solar, so they did not qualify, and 5 didn't qualify due to the 80% TSRF requirement. That means that 40% of that installer’s battery customers were not able to take advantage of REF in 2022.

Enphase Energy-3
RIE’s Proposal Will Decimate Battery Enrollment

Consistency and predictability are key to developing and maintaining a successful DR program, especially for residential batteries. Guaranteeing at least 5 summers at a fixed incentive rate allows customers to make decisions about installing a battery system and participating in the DR program. Reducing the DR program incentive schedule to anything less than a 5-year incentive guarantee would have a major impact on a customer's value proposition and their decision to install batteries and enroll in the DR program. Also, without consistent and predictable year over year program incentives, it becomes very difficult for solar and battery installers to market a compelling value proposition to potential customers. For example, reducing the ConnectedSolutions program incentive rate and/or schedule in 2024 will turn-off most potential customers from considering installing batteries and enrolling in the DR program, and if incentives later increase (e.g., return to the previous level), many customers and OEMs will wait to see if incentives go up further before committing to participate in the program.

Furthermore, changing the incentive rate or schedule on extremely short notice (i.e., by April 1, 2024) is very disruptive to all program participants including customers, solar and battery installers, distributors, and battery OEMs, who are actively marketing the program with the current incentives. For example, it can take many months for installers and OEMs to formulate a customer marketing strategy, and several more months to execute that strategy (e.g., customer value prop evaluation, installer trainings, and creation of marketing materials including customer brochures, program webpage updates, customer marketing emails), which would result in additional battery deployment and enrollments into the program. Affected stakeholders need at least 9 months after any final decision is made before a major change like this is enacted, so they have time to effectively communicate changes to customers and prevent a poor customer experience.

In addition, unlike other DR options, the current ConnectedSolutions Battery DR Program incentive rate directly supports local jobs because the incentives are used by local solar and battery installers to sell residential battery systems to RIE customers. If the current ConnectedSolutions Battery DR Program incentive rate is reduced from $400 to $200/kW-yr, installers' battery business would likely decrease to at least one quarter of what is being installed today, which would have a significant impact on the ability for these installers to support their current local workforce.

If the RIE incentive schedule is also reduced below 5-years, new battery installations and enrollments could plummet to levels not seen in Rhode Island since before the ConnectedSolutions Battery DR program began. This comes at a time when residential solar installations are slowing nationwide due to high interest rates. Residential batteries, which can currently be financed using the 0% interest HEAT Loan in Rhode Island and Massachusetts, are an important lifeline that is helping to keep solar and battery installers employed during the current high-interest rate environment. Additional cuts to the HEAT Loan on top of the other reductions proposed in the most recent RIE Draft SRP Investment Proposal will take away this important lifeline.

Enphase Energy-4
Residential Battery Benefit Potential is Large

We believe residential batteries are more reliable, environmentally healthy, and environmentally responsible compared to other DR options. Residential batteries don't emit any emissions when operated

or when charged by 100% renewable power from residential rooftop solar. Also, residential batteries can more reliably supply DR than other options, because they are not limited due to customer fatigue like thermostat programs, especially during long-duration or multi-day events, and they are not limited due to poor availability like electric vehicle (EV) charging programs, since EVs are not always plugged in and charging when DR is needed most. In addition, because participants are only incentivized for the power they actually deliver during DR events, and there are no upfront or fixed incentives, the ConnectedSolutions Battery DR Program is very cost-efficient with no wasted incentives on customers who do not participate or do not deliver the expected DR performance.

Importantly, in addition to reducing electricity supply costs and avoiding electric system infrastructure investments, residential batteries provide local resiliency (i.e., on-site back-up power and alleviating demand for emergency services), which thermostat, EV charging, and most commercial DR programs cannot provide. For example, residential batteries can reliably provide on-site power to customers during grid outages, even very long-duration outages when paired with solar (i.e., solar-plus-battery configuration).

Enphase Energy-5
Residential batteries offer a very compelling opportunity to leverage customer-sided resources for the benefit of the grid, which will be increasingly more critical as Rhode Island experiences higher demand due to beneficial electrification (EVs and heat pumps) and global climate change. We believe RIE, like many utilities, is just beginning to scratch the surface in terms of being able to quantify and monetize the value from residential batteries through grid services programs like ConnectedSolutions. We recognize that Grid Modernization and RI PUC Docket 5000 will enable RIE and Rhode Island regulators to be able to more fully evaluate, quantify, and monetize additional energy storage benefits that are currently difficult to estimate. In the meantime, given the significant benefit and monetization potential of residential batteries, and disruption to all stakeholders (including customers, solar and battery installers, DERMS provider, and battery OEMs) if the incentive is changed so abruptly, we believe it is premature to reduce the incentive rate or schedule for the ConnectedSolutions Battery DR Program or HEAT Loan eligibility at this time.

Instead, we implore RIE to work with EERMC consultants, local solar and battery installers, residential battery OEMs, and other industry representatives to develop and review an updated benefit-cost analysis (BCA) using the Rhode Island Test, and then determine what the appropriate long-term customer incentive should be based on the updated BCA results. The updated BCA should consider the current and expected future benefits (e.g., emergency load reduction, frequency response distribution network management) from this important DR resource, including those that can be derived from Grid Modernization and RI PUC Docket 5000, and the impact on the local economy. For example, we believe RIE should include environmental, economic development, and reliability benefits in their BCA, which they don’t appear to include in their current cursory benefit assessment.

We strongly believe the quantification of these benefits, and all other costs and benefits that could have significant impact to Rhode Islanders, need to be assessed by RIE, the EERMC, and EERMC consultants with input and review by local solar and battery installers, residential battery OEMs, and other industry

experts before making any decisions related to the ConnectedSolutions Battery DR Program incentive rate or schedule.

NECEC Comments
NECEC, a stakeholder organization, submitted written comments to Rhode Island Energy and the Council on October 18, 2023.

NECEC-1
NECEC thanks RI Energy for leading the SRP development process and for the opportunity to provide feedback on the proposed changes to the ConnectedSolutions program design.

NECEC-2
Program changes should only affect new battery project entrants, not existing participants. Installing a storage system is an expensive investment, so it is likely that customers factor incentives into their decision-making process when deciding to invest in a battery installation. We suggest grandfathering any project that has submitted an interconnection application. By ensuring that the projects that are already underway are not negatively impacted, Rhode Island will support and encourage the growth of the battery market in the state.

NECEC-3
The program should provide a 5-year rate lock. Again, due to the large costs involved in battery installation, it is important to provide stability and support to customers. A five-year rate lock for all battery connections, those already underway and those that will come in the future, will create a more attractive financial incentive and make this investment more attainable.

NECEC-4
The design of a battery incentive cap should not hinder the development of larger battery installations. While a cap can prevent a single customer from using a disproportionate amount of the program budget, NECEC is concerned that the cap might act as a disincentive for building larger, more cost-effective projects. Installing battery storage is an expensive undertaking that greatly benefits from economies of scale, so a battery incentive should also encourage the development of battery systems that offer more storage capacity per dollar spent. This pertains especially to batteries near 5MW, which are not yet utility-scale but might miss out on the incentive if the cap is set to a single-household level.

NECEC-5
An alternative approach to ensuring fair distribution of funds across batteries of various sizes would involve implementing a fund allocation system that devotes a certain percentage of its funds to smaller batteries, but pays incentives proportionately to the size of the storage. This program structure would maximize incentive value by fostering more economical development, while also ensuring a diverse array of storage systems.

NECEC-6
NECEC encourages RI Energy to provide an analysis of potential program attrition that would result from lowering the incentive in Battery Energy Storage Dispatch. A Rhode Island-specific, evidence-based projection of participant losses that could result from a less favorable incentive structure would give a more accurate picture of the net benefit of said change. NECEC supports RI Energy's desire to increase enrollment, and believes this will be most accurately assured by providing both the expected gains and losses that result from a change in incentive.

Newport Solar Comments
Newport Solar, a solar energy company, submitted written comments to Rhode Island Energy and the Council on January 12, 2024 and January 24, 2024.

NS-1
Reading RIE's proposal has us at Newport Solar concerned for the implications this will have on our battery clients and the feasibility of the program to achieve the desired results; customers participating to lower rates by savings on peaker-plants.

If paying for the service of batteries at $400/kw encouraged 8,000 participants and saved $74M, why cut the incentive over 30% and discourage participation? Why not keep it at $400/kw and try to achieve 16,000 participants for $118M savings? So why the drastic cut to the incentive?

Unfortunately, we all seem to have missed the detail that a 5-year rate lock only happens if it's in the "budget". I'm not sure where the referred to budget comes from, but if a peaker plant is needed to keep the lights on, I would imagine RIE doesn't say, 'no, that's not in the budget, roll the blackouts'.

NS-2
The Connected Solutions program has played a key role in residential customers' decision to add energy storage to their home. Residential scale battery technology is an evolving market. As new technologies become available to homeowners, cost remains a burden in implementation. In our experience, only 20% of customers are installing solar and batteries at the same time. This means that 80% of solar customers are not installing energy storage with their solar projects. Some customers are considering energy storage after having solar for a few years. It is our opinion that the Connected Solutions incentive of $400/kW discharged/ season should not be reduced if RI Energy hopes to attract new participation.

NS-3
It is important to note existing energy storage incentives available to residential customers in Rhode Island. The claim that existing state incentives for energy storage help to justify a reduction in the Connected Solutions incentive is misguided. Though the RI Renewable Energy Fund (REF) does have an energy storage incentive, this is available only when installing energy storage paired with a *new* solar installation. It is structured as an incentive adder, not as a stand alone incentive. Homeowners with existing solar cannot receive the energy storage incentive. Additionally, homeowners with a roof “Total Solar Resource Factor” below 80% are ineligible from participating in the REF grant program. Residential customers pursuing the Re-Growth (REG) Program are also not eligible to receive any incentive from the REF. REG and Net Metering no-grant projects are the majority of installations in RI, making the Connected Solutions Program, effectively the only state level incentive available to the majority of battery installations.

NS-4
Comparing RI energy storage system incentives with that of other states is also ill advised. The energy storage incentives in Massachusetts differ from those in RI. It appears that Massachusetts residents can participate in the MA SMART Program with energy storage and receive an incentive directly from the

state. Connected Solutions discharge events count towards this SMART incentive: (https://www.eversource.com/content/residential/save-money-energy/energy-efficiencyprograms/demand-response/battery-storage-demand-response). In this scenario, it is easy to see why a reduction in the Connected Solutions incentive in MA may not have deterred new homeowner's willingness to participate. Rhode Island does not have any comparable incentive.

NS-5

The proposed decrease of over 31% is too much from one program incentive value to the next. The abrupt reduction in incentive may substantially reduce participation. And with a 3-year program, it would take three years of low participation before there'd be an opportunity to increase the incentive to increase participation. The REG program has a history that proves this theory. A decrease of 15% is a more appropriate reduction from one program incentive to the next. A gentler decreasing glide path of the incentive will provide a sense of fairness and instill confidence in the program.

NS-6

Hello EERMC, When Newport Solar recently submitted comments on RIE's proposed Connected Solutions incentive, we were under the impression that it was $275/kw. The RIE proposal now is $200/kw, making our points even more imperative. Cutting the incentive rate in half will undoubtedly reduce participation. Homeowners will not be inclined to manage a complex arrangement with the utility where they are owed money and would have to reconcile a complicated equation to verify their payment for so little money.

This is especially true with the reputation the program has garnered from the botched payment roll out in the first year of the program. Some payments came as virtual credit cards that were not of much value to some participants, and several months late; six months in some cases. As we stated in our comments, a reasonable reduction in incentive of +/-15% per program block would be a much better managed decrease in incentive that would see continued meaningful participation.

Smart Green Solar Comments
Smart Green Solar, a solar installer company, submitted written comments to Rhode Island Energy on December 7, 2023 and January 5, 2024.

SG-1
Lock-in Current Incentives. The residential battery storage incentive should not be decreased. If anything, it should be locked at the current rate for 10 years with event durations fixed. This will allow benefits to be received after the 7-year heat loan is paid off making the monthly payment more affordable to the average consumer. This also makes the incentives easy to understand for all and, ultimately, drives up demand for storage. Currently, we seem to be leaving consumers and solar installers confused as to the gray areas of current policy and how to calculate and explain longer-term potential benefits.

SG-2
Simplify Incentives. Customers need clarity. Currently, we can only offer customers a "TBD" to describe what happens after year three to their incentive. The current proposal states, "This five-year rate lock is and was always subject to approval of annual budgets." We, as a company, have come under security because we have a hard time explaining all available incentive options to consumers. How can we protect the consumer if the program is not simplified and made more clear to them and small businesses like us? We should consider a model similar to states like Massachusetts and Connecticut where rates are locked and guaranteed for longer periods of time.

SG-3
Create A Fixed Rate. Should other state programs even be considered if they introduce bias and limit ceilings of what benefits the state could receive from battery storage programs? Green Mountain Power in Vermont has created a program providing an upfront incentive with mutually beneficial risk for system performance. The grid will always need to purchase power from a source so this seems to come with little risk. If anything, the rate at which the grid purchases power is likely to increase over time and not decrease. This would create a fixed rate that can be relied upon by the grid and consumer. The benefits can clearly be seen in this article. Why shouldn't Rhode Island lead the way by creating similar creative programs to continually increase adoption and testing their own models?

SG-4
Increase Battery Storage Capacity. We recommend an increase in battery storage capacity and not less, as it would benefit the residents of Rhode Island and the distribution companies best. We believe this could best be accomplished with a guaranteed 10-year incentive locked at $400 per kW delivered (average) for a fixed duration of 2 hours per event.

SG-5
Model Program Based On More Representative States. The SRP proposal is modeled on Massachusetts which mandates that only 25% of electrical consumption come from renewable sources by the year 2030. Rhode Island cannot follow their model if our goal is to achieve 100% of electrical consumption from renewable energy sources in that same time period. Vermont has a 71% goal and is still taking a more aggressive approach than Rhode Island with respect to program incentives.

SG-6

Consider Modifying the Program Design Principles. The program design principles seem to contradict one another. You cannot be agnostic towards technology and participants and encourage diffuse and diverse participation for reliable response and comply with least-cost procurement standards. This leads to a lower cost for some renewable energy sources and greater cost for others just to ensure an even distribution of technologies. This does not result in the lowest cost solution and limits the potential growth of technologies that may offer better solutions.

Sunrun Comments
Sunrun, a solar and battery storage company, submitted written comments to Rhode Island Energy on January 17, 2024.

SR-1
Avoided Energy Cost. We want to flag that the data used from the 2021 AESC may be outdated (using 2018 data) and is worth updating to ensure a more accurate picture.

Second, batteries are key in reducing peak load. We would like to discuss further how best to incorporate that value in the proposal as well as additional clarification on the modeling used to value battery exports. Here is language from the Illinois Commission Order in Ameren IGP docket (23-0487) at p. 178 addressing this topic directly:

"Staff asserts that a VPP program seems to merely shift supply from traditional generation to battery storage and questions whether it results in any actual peak load reduction. The Commission finds that this is precisely how such a program will achieve peak load reduction; during peak hours, supply that would otherwise come from traditional generation—and possibly more expensive, peaking generation—comes in part from battery storage, thereby reducing the supply required from traditional generation during those hours."

SR-2
Avoided Capacity Cost. We would like clarification on the Generational value to ensure battery exports are valued properly, regardless if they serve on-site load or not:

"Note that the Total Summer Generation value is only applicable to batteries that serve on-site load. For batteries that export to the grid during peak, the Total Summer Generation value is closer to $0/kW."

RI and MA battery behaviors are the same under ConnectedSolutions. Battery export should be also counted forward capacity credit. Behind the meter solar + battery can participate in ISO-NE FCM capacity market via On-Peak demand resource model for example. The capacity performance is measured at the battery inverter level and export is included for capacity compensation in the ISO market.

SR-3
Avoided Infrastructure Cost. We agree that avoided infrastructure costs should be included in the value stack, but would like additional clarification on how RIE plans to calculate those costs.

SR-4
Value of Reliability. We would like additional clarification on the calculation behind the value of reliability. We believe it should be included in the value stack.

SR-5
Regional Network Service (RNS) Cost. Would like to discuss in more depth the difference in value between "on-site batteries for load shed only" vs "energy exports."

SR-6

Operational Timeline. Aggregators, such as Sunrun, require a longer timeline to implement proposed changes. The proposed February 2024 date does not allow an action window for customers sold the benefits of the current program to be installed, activated, and enrolled. Sunrun recommends a June 1, 2024 deadline that aligns with the start of the 2024 season. This will ensure the proposed changes are made to customer terms, and action-window for customers to prevent poor customer experience.

SR-7

- Provide clarification on how the standards required in "system reliability procurement" benefit cost analysis interact with this 2017 docket: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4600-WGReport_4-5-17.pdf
- Including the special value of GHG emissions reductions (included in Massachusetts), and other societal / non-energy values.
- Avoided non-electricity fuel charges: Deliverable fuel benefits (NG & other fuels) is the consumption of these other fuels reduced by use of this program, and has been included in other programs (MA).
- Water, sewage, and disposal benefits (included in MA ConnectedSolutions)

NEC Solar Comments
NEC Solar, a solar company, submitted written comments to the Council on January 25, 2024.

NEC Solar-1
At a time when we should be encouraging battery storage use, these proposed changes will further discourage interest.

Most solar customers decline investing in battery storage due to the cost. These proposed changes will only reduce consumer interest.

Due to the likely reduction in battery storage adoption by RI ratepayers, I support the request to conduct a thorough analysis of these proposed changes and their impacts on the industry and the environment and encourage a review of alternate options and incentives.

Sol Power Comments
Sol Power, a solar and battery storage company, submitted written comments to the Council on January 23, 2024.

SP-1
Sol Power solar has installed 212 solar and battery backup systems over the past 11 years, making us one of the largest solar battery providers in the state. The proposed decrease for the Connected Solutions residential battery demand response incentive would create a dramatic reduction in battery backup adoption for solar, and cause a proportionately large distress for our business.

The current connected solutions battery incentive of $400/kW for 5 years results in an expected incentive payout of roughly $5,000 over 5 years for our customers for a Powerwall battery. The proposed incentive in the "Rhode Island Energy SRP Plan Proposal" linked on the RIEERMC website (I do not see a rev number or date on the proposal) is $200/kW for 3 years, resulting in $1,500 over 3 years for our customers for a Powerwall battery. Decreasing the Connected Solutions battery incentive from $5,000 to $1,500 for our customers is beyond a reasonable threshold and would nearly eliminate demand for battery backups with solar.

SP-2
We have been installing solar with battery backups in RI for 11 years. Battery storage as a technology is significantly older than that. Prior to the launch of the Connected Solutions incentive we installed an average of 1.2 battery systems per year. Since the launch of the RI Connected Solutions storage incentive we have installed an average of 40.75 battery systems per year. A primary reason for this dramatic increase in battery adoption is that the Connected Solutions incentive made a solar battery backup cost less than a fuel powered backup generator.

We install both battery backups and fuel powered backup generators. When generators were cheaper than batteries, our customers purchased generators almost exclusively. Currently batteries are cheaper than generators, and our customers purchase batteries almost exclusively for backup power. If the Connected Solutions incentive is decreased to $200/kW for 3 years then a generator will be cheaper than a battery installation for backup power, and demand for solar batteries will drop off almost entirely as customers will prefer the cheaper backup power solution.

SP-3
In response to the claim that our customers can fall back on other state incentives, only 43% of our battery installations sold in 2023 were eligible for the state's Renewable Energy Fund (REF) storage incentive. The majority of our battery installations do not qualify for the REF storage incentive. For systems that are eligible, the REF storage incentive covers 6% of our average storage system cost, while the current Connected Solutions incentive covers 40% of the storage system cost.

Third party study of the Connected Solutions program performed by the Clean Energy Group found the cost/benefit rate of the Connected Solutions program to be well above 1 for a diverse range of tests. This includes a ratio of 2.15 for the Ratepayer Impact Measure (RIM) test. The report can be found at the following link and the cost/benefit test results are found on Page 33.

https://www.cleanegroup.org/wp-content/uploads/connected-solutions-policy.pdf

Decreasing the Connected Solutions residential battery incentive from $5,000 ($400/kW, 5 years) per battery to $1,500 ($200/kW, 3 years) for our customers will virtually eliminate battery storage adoption in RI. In turn this will dramatically harm our business and the solar industry of RI. Third party analysis of the current incentive (linked above) shows a beneficial cost/benefit ratio for ratepayers. Sol Power has strong objections to the proposed changes due to the harm it will cause the state's solar industry, and we believe that the current incentive levels are justified by the benefits to ratepayers.