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Rhode Island Energy™
a PPL company

March 21, 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 – Connected Solutions
<u>Responses to Division Data Requests – Set 1</u>

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed are the Company's responses to the Division of Public Utilities and Carriers' ("Division") First Set of Data Requests in the above-referenced matter.

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

Division 1-1
Avoided Transmission and Distribution

Request:

The Company states that "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." (Bates page 138) and that "this methodology produces a proxy for average distribution cost to serve 1 kW." (Joint Testimony, page 20, lines 2-3)

In executable format, provide all data, evaluations, planning documents, assumptions, workpapers and any information relied upon to derive the avoided distribution infrastructure cost of $120/kW.

Response:

The Company reviewed avoided distribution infrastructure costs used in its benefit-cost assessment models over the prior five years.* This review showed an increasing trend in avoided distribution infrastructure costs (from ~$80/kW per year in 2020 to ~$170/kW per year in 2024). The Company's objective with ConnectedSolutions is to derive net utility system value – in terms of avoided electric bill costs – from reducing regional coincident peak demand. Given the year-over-year changes in estimated avoided distribution infrastructure cost, the Company thought to use a manufactured value for avoided distribution infrastructure cost in its program design to hedge against the risk of further year-on-year changes in avoided distribution infrastructure cost in 2024-2026. Specifically, the Company used a value that roughly reflected an average of the prior estimates and that the Company was confident would be a plausible lower bound to actual avoided distribution infrastructure costs resulting from regional coincident peak demand reduction. The Company thought it appropriate to use this same 'planning value' of avoided distribution infrastructure cost in its proposed performance incentive mechanism to tie the Company's performance incentive to program design. This point – limiting risk of not achieving value from avoided infrastructure cost – is illustrated with the two examples below.

If the Company were to have used the avoided distribution infrastructure cost estimated in 2020 (roughly $80/kW per year) as its planning value, then the Company would have revised customer incentive levels to be lower than proposed. Since avoided distribution infrastructure cost estimated have increased over the last five years, and with the continued policy signals encouraging electrification, it is likely that actual avoided distribution infrastructure value may be higher than $80/kW per year in 2024-2026. Therefore, the risk of using $80/kW per year as a

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Avoided Transmission and Distribution

planning value is setting incentive levels too low, thereby resulting in lower participation and less realized avoided electric bill value.

On the other hand, if the Company were to have used the avoided distribution infrastructure cost estimated for 2024 (roughly $170/kW per year) as its planning value, then the Company may have allowed incentive levels to be higher than proposed. Since the estimated avoided distribution infrastructure cost in 2024 is substantially higher than the estimated avoided distribution infrastructure cost in 2023 and prior years, there is non-zero risk that the actual value of avoided distribution infrastructure cost realized in 2024-2026 is lower. Therefore, the risk of using $170/kW per year as a planning value is setting incentive levels too high, thereby resulting in higher costs and less avoided electric bill value.

The Company used $120/kW as its avoided distribution infrastructure cost planning value for program design purposes in 2024. The Company multiplied this value by an inflation rate of 1.35% to obtain avoided distribution infrastructure cost values of $121.62 and $123.26 in 2025 and 2026, respectively.

*For reference, the following table includes the estimated values of avoided distribution infrastructure cost for each year that the Company considered in its review.

	(a)	(b)	(c)
	Year	**Source**	**Avoided Distribution Infrastructure Cost (Dollar Year)**
(1)	2024	23-35-EE	$174.41 (2023)
(2)	2023	22-33-EE	$121.58 (2022)
(3)	2022	5189	$100.02 (2021)
(4)	2021	5076	$80.24 (2017)
(5)	2020	4979	$80.24 (2017)

Prepared by or under the supervision of: Carrie Gill and Ryan Constable

Division 1-2

Avoided Transmission and Distribution

Request:

How does the Company's current methodology to calculate avoided distribution infrastructure differ from the methodology used under National Grid ownership? Please discuss each component used to derive avoided distribution infrastructure, comparing and contrasting the previous methodology to the current methodology.

Response:

The Company's current methodology to calculate avoided distribution infrastructure cost does not differ from the methodology used under National Grid ownership. Specifically, the Company has used and continues to use the methodology as described in and informed by the AESC Study (see chapter 10, "Transmission and Distribution" of the 2024 AESC Study, page 270).[1]

The Company chose to use a different value of avoided distribution infrastructure costs to inform program design and the proposed performance incentive mechanism for ConnectedSolutions in 2024-2026 with the intent of optimizing net utility system benefits and hedging risk. Please refer to the Company's response to Division 1-1 for an explanation of the Company's derivation.

[1] The Avoided Energy Supply Components ("AESC") in New England 2024 Report may be viewed at: https://www.synapse-energy.com/sites/default/files/inline-images/AESC%202024.pdf

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Division 1-3
Avoided Transmission and Distribution

Request:

How did the Company derive a +/- $40/kW factor resulting in a $120/kW avoided distribution cost? What contributed to the variability, and would future avoided infrastructure costs include this level of variability?

Response:

The Company determined the +/- $40/kW uncertainty band based on the rough difference between its chosen planning value of $120/kW and the minimum/maximum avoided distribution infrastructure cost estimates in the past five years. Specifically, the smallest avoided distribution infrastructure cost estimate over the last five years was ~$80/kW, which is about $40/kW less than the planning value. The largest avoided distribution infrastructure cost estimate over the last five years was about ~$170/kW, which is about $50/kW more than the planning value. The Company used the smaller of the two differences to form a symmetrical uncertainty band about the planning value. This uncertainty band was used as an illustrative tool used in program design to showcase how the Company did not align incentive levels to a value with precision to the cents level. (Please refer to the Company's response to DIV 1-29 for more discussion about the Company's approach to accounting for uncertainty.) Please note that the Company does not propose to use this uncertainty band in its proposed performance incentive mechanism.

Division 1-4
Avoided Transmission and Distribution

Request:

The 2021 AESC Study (page 236) recommends selecting a period for analysis which may be historical, prospective, or a combination of the two. Why did the Company choose a time period of 2021 to 2024? The 2021 AESC report (page 255) also indicates that National Grid used a relatively short period of 11 years (5 years of historical data and 6 years of forecasted data) which may not be long enough to account for lumpiness associated with investments across the years. Why did the Company choose a shorter period of time given the AESC Report observations and recommendations?

Response:

To clarify: the Company's methodology for estimating avoided distribution infrastructure cost does not differ from the methodology the Company used under National Grid ownership (please refer to the Company's response to Division 1-2).

The Company used five years of forecasted data (limited by the five-year outlook of the Company's capital forecast), present year values, and five years of historical data in its estimation of avoided distribution infrastructure cost.

Please refer to the Company's response to Division 1-1 for a comparison of avoided distribution infrastructure cost estimates to the planning value used in program design and in the proposed performance incentive mechanism and an explanation of the Company's reasoning for using a planning value that differs from the avoided distribution infrastructure cost estimate.

Division 1-5
Avoided Transmission and Distribution

Request:

To the extent applicable to the Company's current methodology to calculate avoided distribution, how does RIE incorporate the 2021 and 2024 AESC Report (pages 255 and 292 respectively) assessment and recommendations on improvement?

Response:

Referring to each row of recommendations in Table 133 of the 2024 AESC (available at this link on PDF page 309: https://www.synapse-energy.com/sites/default/files/inline-images/AESC%202024.pdf and reproduced below for easy reference):

Division 1-5, page 2
Avoided Transmission and Distribution

Table 133. Assessment of National Grid's avoided distribution methodology and recommendations for improvement

Topic	Overall Assessment	Recommendations on Improvement	Recommendations on Clarity
Overall T&D Methodologies	The methodology is mostly consistent with recommended methodologies in its consideration of load-growth-related T&D investments.	National Grid should account for non-PTF transmission costs.	-
Categories of investments considered	National Grid uses historical and forecasted T&D investments and assumes a percentage of that investment is related to load growth not associated with new business and is therefore avoidable with DSM.	It is not clear how the percentage of avoidable distribution investments were calculated since they are significantly lower than the overall distribution investments. It is unclear whether this estimate of the avoidable investments reflects all load-growth-related projects, including any capacity-related projects undertaken for non-load growth purposes such as reliability improvements.	National Grid should provide more transparency regarding the calculation of percentages representing load growth and new business. National Grid should use a more granular approach in the breakout of its T&D investments.
Load Forecast Methodologies	National Grid includes the impact of historical adoption of energy efficiency measures but does not include the impact of forecasted energy efficiency adoption.	National Grid should use a load forecast that includes future projected energy efficiency savings since the investment forecast assumes continued energy efficiency programs.	-
Detailed Considerations	National Grid uses a relatively short period of 11 years (5 years of historical data and 6 years of forecasted data) which may not be long enough to account for lumpiness associated with investments across the years. National Grid applies a carrying cost to investments when calculating avoided costs. National Grid includes both O&M and overhead costs in calculation of avoided costs.	National Grid should use a longer-term period for its analysis, in the range of 25–27 years.	-

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Division 1-5, page 3

Avoided Transmission and Distribution

The Company has developed and accounts for non-PTF transmission value.

1. The Company used a percentage of avoidable distribution investments developed from the Electric Infrastructure, Safety, and Reliability ("ISR") Plan.

2. The Company acknowledges that the capital forecast incorporates the effects of energy efficiency and would be greater if energy efficiency were not included. Therefore, the Company believes that the value of avoided distribution infrastructure cost estimated is plausibly conservative.

3. The Company's forecasted horizon is limited by its capital forecast, which is a five-year outlook. Using a 25-year period would, therefore, require twenty years of historical data which would over-weight historic investments and plausibly result in an underestimate of avoided distribution infrastructure cost.

Division 1-6

Avoided Transmission and Distribution

Request:

Did RIE use a top down (using FERC Form 1 data), or a bottom-up analyses (2021 AESC Study, pp 242-244)? How was this decision made? Explain how RIE identified and included only load-related costs and excluded non-load-related investments such as meters, new services, asset condition equipment replacements, system performance, etc.

Response:

The Company used the methodology recommended by the 2021 AESC to derive its avoided distribution infrastructure cost estimate for 2024: this methodology employs a top-down accounting approach, based FERC Form 1 data and the ISR "System Capacity and Performance" category of capital investments to determine the percent of capital forecast associated with load growth that would be deferrable. This decision was made with the objective of being consistent with the methodology used to assess the degree of cost-effectiveness of energy efficiency programs.

Please refer to the Company's response to Division 1-1 for a comparison of avoided distribution infrastructure cost estimates to the planning value used in program design and in the proposed performance incentive mechanism and an explanation of the Company's reasoning for using a planning value that differs from the avoided distribution infrastructure cost estimate.

Division 1-7
Avoided Transmission and Distribution

Request:

Please provide the Company's documentation that explains specific projects or accounts that are classified as avoidable or unavoidable when determining avoided distribution infrastructure costs. Include a description of all categories or projects designated as avoidable, referencing the classifications used in ISR Planning where applicable.

Response:

The Company's estimate of deferable infrastructure is not tied to specific projects, but to the category of projects contained within each year's ISR's "System Capacity and Performance" category of capital investments.

Division 1-8
Avoided Transmission and Distribution

Request:

If a project is classified as avoidable, does the Company assume it is avoided in its entirety, deferred for some period of time, or other? Explain how the assumption informs the calculation of the average avoided distribution infrastructure cost of $120/kW.

Response:

Please refer to the Company's response to Division 1-7.

The Company does not estimate avoided distribution infrastructure costs on a project-by-project basis for activities that are not locational in nature. This type of locational analysis is appropriate for assessing net value of, say, a wires solution compared to a non-wires solution. Demand response achieved through ConnectedSolutions as proposed for 2024-2026 does not have this type of locational component to it; participation is essentially homogenous across the state, geographically unconstrained, and timed to reduce regional coincident peak demand rather than locational load constraints. In this case, the Company considers a top-down jurisdiction-wide average dollar-per-kW approach to be an appropriate representation of the average value of avoided distribution infrastructure costs for a non-locational program. Please refer to the Company's response to Division 1-1 for a comparison of avoided distribution infrastructure cost estimates to the planning value used in program design and in the proposed performance incentive mechanism and an explanation of the Company's reasoning for using a planning value that differs from the avoided distribution infrastructure cost estimate.

Division 1-9

Avoided Transmission and Distribution

Request:

Explain how the Company translates the avoided distribution cost into an avoided electric bill cost for each program year. Please provide underlying assumptions and calculations.

Response:

The Company assumed the planning value ($120/kW) for avoided distribution infrastructure cost would translate to that exact decrease in total collections, normalized by forecasted kWh sales. Please see the following tabs in the Benefit-Cost Assessment Tool for assumptions and calculations: Lookups, Impacts, Calcs, Participants, Benefits, and RateBill.

Division 1-10
Avoided Transmission and Distribution

Request:

The Company calculates benefit/cost ratios of 1.19, 1.29, and 1.34 for each year from 2024 – 2026. What are the benefit-cost ratios for each year assuming that avoided distribution infrastructure is a) $40/kW lower and b) $40/kW higher?

Response:

Please see the table below.

	(a)	(b)	(c)	(d)
		Current BCR values	**BCR with lower $40/kW**	**BCR with higher $40/kW**
(1)	2024	1.19	1.05	1.33
(2)	2025	1.29	1.14	1.43
(3)	2026	1.34	1.19	1.48

Column (b) is for current values assumed in the model.

Column (c) is for $40/kW lower.

Column (d) is for $40/kW higher.

Prepared by or under the supervision of: Lado Kurdgelashvili and Carrie Gill

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Division 1-11

Avoided Transmission and Distribution

Request:

Is the Company considering plant in service or actual spend during the 2021-2024 time period to calculate avoided distribution?

Response:

According to FERC Form 1, Page 204-207 (before 2021, page 206), line 75 / column c for distribution, the capital investment numbers are for "electric plant in service".

Division 1-12
Avoided Transmission and Distribution

Request:

The Company has developed a proposed Long-Range Plan that includes projects related to system capacity and load relief investments through FY 2034 (FY 2025 ISR Plan, Book 1 of 3, Bates pp 152-154). Why didn't the Company select this prospective investment time period to estimate avoided distribution costs?

Response:

The Company used the methodology described in and informed by the 2021 AESC to estimate avoided distribution infrastructure cost for 2024. The Company used a different planning value for purposes of program design and in the proposed performance incentive mechanism. Please refer to the Company's response to Division 1-1 for a comparison of avoided distribution infrastructure cost estimates to the planning value used in program design and in the proposed performance incentive mechanism and an explanation of the Company's reasoning for using a planning value that differs from the avoided distribution infrastructure cost estimate.

Division 1-13
Avoided Transmission and Distribution

Request:

Does demand response avoid any of the following System Capacity & Performance investments: Volt Var Optimization, 3V0, Mobile Substations, DER Monitor/Manage, Fiber Network, IT Infrastructure, Mobile Dispatch, CEMI-4 Program, Engineering Reliability Review Program, Distribution Automation Recloser Program, ADMS/DERMS, or the Electromechanical Relay Replacement Program? Explain.

Response:

No, demand response through ConnectedSolutions 2024-2026 does not and/or cannot avoid any of the referenced investments. Further explanation is below:

- Volt Var Optimization investments are based on energy reduction across all hours. Demand response provides some ancillary energy reduction during only peak hours, so it does not avoid the need for investment in VVO.

- 3V0 is a protection system that is needed independent of peak load.

- Mobile substations are justified based on major asset risks and contingency risks, which are independent of demand response.

- ADMS, DERMS and (synonymously) DER Monitor/Manage are further justified as the number of distributed energy resources – including those used to participate in demand response – increase. Indeed, with ADMS and DERMS, the Company will be able to allow for (and encourage more) complex demand response schemes that may provide locational value (i.e., deferred capital to resolve a load constraint) beyond reducing regional coincident peak load.

- Fiber, IT infrastructure, mobile dispatch, electromechanical relays are unrelated and independent of demand response.

- CEMI-4, ERR, DARP are reliability programs that are concerns with the number of customers affected; they are independent of demand response.

Prepared by or under the supervision of: Ryan Constable

Division 1-14
Avoided Transmission and Distribution

Request:

What was the actual/estimated annual peak load from 2021-2024? What is the forecasted annual peak load for 2024-2027? Please provide the source for the data.

Response:

Please refer to the Table on PDF Page 30 of the 2022 Electric Peak (MW) Forecast, available here: https://systemdataportal.nationalgrid.com/RI/documents/RI_PEAK_2023_Report.pdf, copied below for easy reference. Please note that this forecast includes distributed energy resources; peak demand reduction from demand response is included in the peak load actuals and forecast.

Division 1-14, page 2

Avoided Transmission and Distribution

NECO
SUMMER Peaks

AFTER DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	WTHI ACTUAL
2006	1,985		1,833		1,965		2,002		85.9
2007	1,777	-10.5%	1,884	2.8%	2,034	3.5%	2,077	3.8%	80.9
2008	1,824	2.6%	1,847	-1.9%	1,991	-2.1%	2,032	-2.2%	82.9
2009	1,713	-6.1%	1,849	0.1%	2,014	1.2%	2,061	1.4%	80.3
2010	1,872	9.3%	1,834	-0.8%	1,998	-0.8%	2,045	-0.8%	84.5
2011	1,974	5.5%	1,852	1.0%	2,015	0.9%	2,061	0.8%	84.8
2012	1,892	-4.2%	1,855	0.1%	2,005	-0.5%	2,047	-0.7%	83.5
2013	1,965	3.9%	1,852	-0.1%	2,015	0.5%	2,061	0.7%	84.7
2014	1,653	-15.9%	1,846	-0.4%	2,011	-0.2%	2,057	-0.2%	80.4
2015	1,738	5.1%	1,887	2.2%	2,065	2.7%	2,115	2.8%	80.4
2016	1,803	3.8%	1,813	-3.9%	1,977	-4.3%	2,023	-4.4%	82.6
2017	1,688	-6.4%	1,759	-3.0%	1,923	-2.7%	1,969	-2.7%	81.7
2018	1,847	9.4%	1,807	2.8%	1,973	2.6%	2,020	2.6%	83.4
2019	1,750	-5.3%	1,774	-1.8%	1,966	-0.3%	2,021	0.0%	84.5
2020	1,855	6.0%	1,762	-0.7%	1,925	-2.1%	1,972	-2.4%	84.7
2021	1,819	-2.0%	1,734	-1.6%	1,906	-1.0%	1,955	-0.8%	84.1
2022	1,859	2.2%	1,732	-0.1%	1,907	0.0%	1,956	0.1%	85.0
2023	-	-	1,760	1.6%	1,939	1.7%	1,990	1.7%	-
2024	-	-	1,755	-0.3%	1,936	-0.2%	1,988	-0.1%	-
2025	-	-	1,756	0.1%	1,940	0.2%	1,992	0.2%	-
2026	-	-	1,749	-0.4%	1,934	-0.3%	1,986	-0.3%	-
2027	-	-	1,759	0.6%	1,946	0.6%	1,999	0.7%	-
2028	-	-	1,772	0.7%	1,953	0.4%	2,006	0.4%	-
2029	-	-	1,785	0.8%	1,969	0.8%	2,021	0.7%	-
2030	-	-	1,802	0.9%	1,987	0.9%	2,040	0.9%	-
2031	-	-	1,817	0.9%	2,004	0.8%	2,057	0.8%	-
2032	-	-	1,834	0.9%	2,022	0.9%	2,075	0.9%	-
2033	-	-	1,852	1.0%	2,041	0.9%	2,094	0.9%	-
2034	-	-	1,867	0.8%	2,057	0.8%	2,110	0.8%	-
2035	-	-	1,878	0.6%	2,063	0.3%	2,117	0.3%	-
2036	-	-	1,906	1.5%	2,089	1.3%	2,142	1.2%	-
2037	-	-	1,914	0.4%	2,096	0.3%	2,148	0.3%	-

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.6%	-0.4%	-0.4%
Avg. last 10 yrs	-0.7%	-0.5%	-0.5%
Avg. last 5 yrs	-0.3%	-0.2%	-0.1%
BASE 2022			
Avg. next 5 yrs	0.3%	0.4%	0.4%
Avg. next 10 yrs	0.6%	0.6%	0.6%
Avg. next 15 yrs	0.7%	0.6%	0.6%

WTHI

NORMAL	82.8
EXTREME 90/10	85.5
EXTREME 95/5	86.2

** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response*

Division 1-15
Avoided Transmission and Distribution

Request:

If system peak load growth is minimal, how has RIE adjusted assumptions?

Response:

Peak load growth is minimal because it includes peak demand reductions from a number of distributed energy resources including demand response; therefore, there is no need to adjust assumptions. Please refer to pages 57-58 of the 2022 Electric Peak Load Forecast, available here: https://systemdataportal.nationalgrid.com/RI/documents/RI_PEAK_2023_Report.pdf, copied below for easy reference.

Division 1-15, page 2
Avoided Transmission and Distribution

Demand Response (NECO)

Year	Low - cum	Base - cum	High - cum
2021	32	32	32
2022	32	38	38
2023	32	37	45
2024	32	42	54
2025	16	42	56
2026	16	42	59
2027	16	42	61
2028	16	42	64
2029	16	42	64
2030	16	42	64
2031	16	42	64
2032	16	42	64
2033	16	42	64
2034	16	42	64
2035	16	42	64
2036	16	42	64
2037	16	42	64

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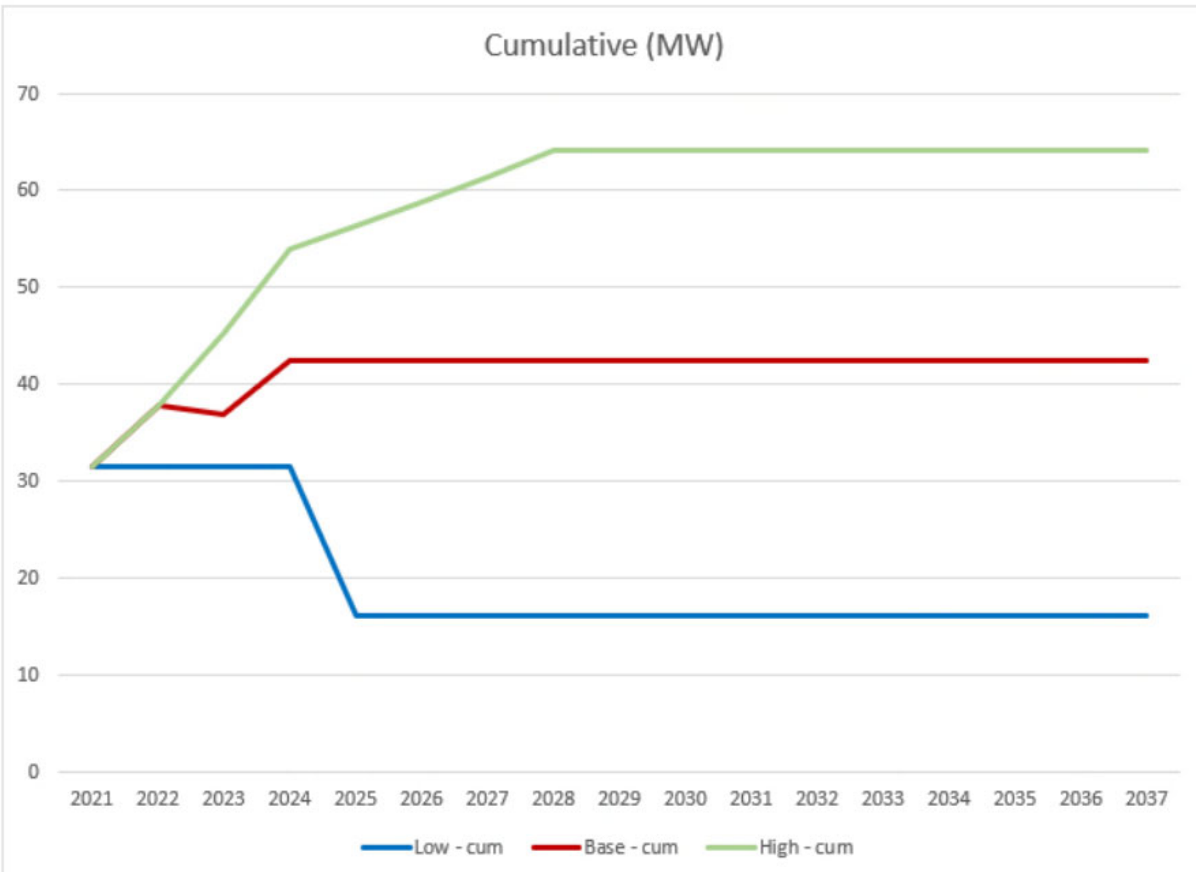
Avoided Transmission and Distribution



Prepared by or under the supervision of: Ryan Constable and Carrie Gill

Division 1-16
Avoided Transmission and Distribution

Request:

Can the Company rely on demand response to avoid investments that resolve contingency load at risk issues (N-1) issues? Are contingency load at risk projects classified as avoidable or unavoidable for the purposes of estimating avoided distribution infrastructure?

Response:

No, the Company cannot rely on voluntary demand response achieved through participation in ConnectedSolutions to avoid investment that resolves contingency load at risk (N-1) issues for the reasons listed herein. First, N-1 issues are specific to a particular location and can happen at any time. ConnectedSolutions does not differentiate between participant locations in determining when to call peak events to achieve demand response nor does ConnectedSolutions ask customers to reduce peak load during off-peak events. Second, participation in ConnectedSolutions is voluntary, not mandatory. Third, using demand response for N-1 issues requires software (ADMS and DERMS) and sensing to identify, communicate, and control demand response devices. Absent a performance guarantee contract and ADMS/DERMS, the Company cannot rely on voluntary participation to resolve N-1 issues.

Please note, for clarity, that the Company is distinguishing between the demand response potential of ConnectedSolutions and other ways of achieving demand response, such as through controlled load shed. The Company's response to this question is only in regard to the former, not the latter.

Division 1-17
Avoided Transmission and Distribution

Request:

The Company previously stated that the Demand Response program was "expected to grow to about 44 MW, or 1.9% of summer peak load by year 2025. No additional incremental DR MW is expected beyond that point because it is assumed that the program's market potential is at its maximum by then, but the cumulated MW is expected to be carried through the rest of the forecast horizon" (FY 2024 ISR Plan, Attachment DIV 1-14, page 14) The Company now indicates potential Demand Response of nearly 56 MW in 2026 (Bates page 115). What changes have occurred to prompt an expanded program?

Response:

This statement is included in each annual forecast and reflects the nature of the forecast assumptions. The Company also includes a high estimate of demand in each forecast in recognition that higher levels of peak demand reduction are plausible. The Company updates its peak demand reduction forecast annually. Please refer to the Company's response to DIV 1-15 and pages 57-58 for these estimates, which include the range of planned peak load reduction in the 2024-2026 ConnectedSolutions, available here:
https://systemdataportal.nationalgrid.com/RI/documents/RI_PEAK_2023_Report.pdf.

Prepared by or under the supervision of: Ryan Constable

Division 1-18
Avoided Transmission and Distribution

Request:

The Company states that the $120/kW +/-$40/kW avoided distribution infrastructure cost is a proxy that 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." (Joint Testimony, page 20, lines 3-7). Explain how RIE justifies a performance incentive mechanism based on program success if avoided distribution, which is the largest component, is imperfect with actual results unobservable?

Response:

The Company justifies its proposed performance mechanism based on the plausible expectation that the avoided electric bill cost value will be realized, and that the performance incentive mechanism may be scaled if lower performance is achieved. Specifically, regarding the value for avoided distribution infrastructure cost used in the proposed performance incentive mechanism, the Company chose the same value it used to inform program design. Although the 2024 avoided distribution infrastructure cost estimate would have led to a larger performance incentive, all else equal, the Company is proposing to use this tempered planning value to parallel program design. Please refer to the Company's response to Division 1-1 for a comparison of avoided distribution infrastructure cost estimates to the planning value used in program design and in the proposed performance incentive mechanism and an explanation of the Company's reasoning for using a planning value that differs from the avoided distribution infrastructure cost estimate.

Prepared by or under the supervision of: Carrie Gill

Division 1-19
Avoided Transmission and Distribution

Request:

The Company indicates that the Schedule 2-Benefit-Cost Assessment Model includes a Docket 4600 output table populated with demand response benefit-cost results (see "Cover" worksheet). Please confirm and reference where the Docket 4600 table is in included in Schedule 2, or if not included, submit Schedule 2 in executable format with the Docket 4600 table.

Response:

Please see the attached Excel version of the updated Schedule 2 with the Docket 4600 table.

Division 1-20
Avoided Transmission and Distribution

Request:

Provide both the Company's total system substation transformer capacity and feeder capacity (Summer Normal) vs. peak load for 2021, 2022, and 2023, and forecasted for each year from 2024-2027.

Response:

The Company's total system substation transformer capacity is 5,920 MVA and the Company's total feeder capacity is 3,661 MVA. Please refer to the Company's 2022 Electric Peak Forecast for actual and forecasted peak load, available here on PDF Page 30 https://systemdataportal.nationalgrid.com/RI/documents/RI_PEAK_2023_Report.pdf and reproduced below for easy reference.

Table: NECO Summer Peaks after DER impacts

	(a)	(b)	(c)	(d)	(e)
	Year	Actuals (MW)	Normal 50-50 (MW)	Extreme 90-10 (MW)	Extreme 95-5 (MW)
(1)	2021	1,819	1,734	1,906	1,955
(2)	2022	1,859	1,732	1,907	1,956
(3)	2023	1,684*	1,760	1,939	1,990
(4)	2024	-	1,755	1,936	1,988
(5)	2025	-	1,756	1,940	1,992
(6)	2026	-	1,749	1,934	1,986
(7)	2027	-	1,759	1,946	1,999

* Updated 2022 Electric Peak Forecast Table (Page 30) with 2023 actual peak.

Prepared by or under the supervision of: Ryan Constable

Division 1-21
Avoided Transmission and Distribution

Request:

In executable format, provide all data, evaluations, planning documents, assumptions, workpapers and any information relied upon to derive the avoided transmission infrastructure cost.

Response:

For avoided Pool Transmission Facilities (PTF), the Company used actual (2024) and projected (2025-2026) Regional Network Service ("RNS") charges (please refer also to the Company's response to Division 1-34). RNS charges are calculated based on monthly Regional Network Load ("RNL"). It is assumed that this program will avoid these charges by reducing RNL load in addition to coincident system load for three summer months for each of the program years.

Avoided non-PTF comes from 2024 Annual Energy Efficiency Plan (RIPUC Docket No. 23-35-EE). This estimate was developed using the ICF model using company-specific information on load growth and investments in non-PTF transmission. The Company has calculated the value of the avoided cost for non-PTF of $11.89/kW-year in 2023 dollars. After accounting for local transmission and distribution losses at 11.2% and for one year inflation adjustment of 1.35% the Company arrives at $13.40/kW for 2024.

Division 1-22

Avoided Transmission and Distribution

Request:

The 2021 AESC Report (Table 108, p. 248) cites an estimate of "The existing value of avoided distribution costs used by utility in evaluating and screening DSM" for Rhode Island as $84.24/kW (2019$). What has changed to bring this number up to $120/kW?

Response:

The equivalent estimate to the $84.24/kW figure in the question is $174.41/kW in 2024. The value listed in the 2021 AESC was developed in 2019. When the Company develops its estimates of avoided distribution infrastructure costs, the analysis takes into account five historical years, the current year forecast, and five future forecasted years, for a total of 11 years of data. The equivalent value of $174.41 was developed in 2023, and so uses a different set of 11 years of data than that used in 2019. The changes in historical and forecasted data between these two sets of 11 years of data result in the different avoided distribution cost values. For example, between 2023 and 2024, the avoided distribution cost increased from $121.58/kW to $174.41/kW. The driving factor that caused this increase was the decrease in the incremental growth in peak demand (the difference between the largest forecast and smallest historic annual peak demands within the 11-year analysis period) from 2023 to 2024.

The Company used a value of $120/kW for program design and in its proposed performance incentive mechanism. Please refer to the Company's response to Division 1-1 for a comparison of avoided distribution infrastructure cost estimates to the planning value used in program design and in the proposed performance incentive mechanism and for an explanation of the Company's reasoning for using a planning value that differs from the avoided distribution infrastructure cost estimate.

Division 1-23
Avoided Transmission and Distribution

Request:

Do the estimates of avoided cost include any general plant components or is it strictly based on distribution (and transmission) plant?

Response:

The estimates of avoided cost do not include any general plant components.

Prepared by or under the supervision of: Ryan Constable and Michael O'Brien Crayne

Division 1-24
Avoided Transmission and Distribution

Request:

Confirm or correct the following: the Company's AESC estimates for marginal costs going forward are derived from historical data.

Response:

The Company estimates the value of peak demand reduction at the level at which our customers would otherwise pay 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. The highlighted values (rows 3, 4, 6, and 7) were calculated based on the AESC 2021 (column b) and AESC 2024 (column c). AESC values are estimated based on future energy market projections. Other values reported in the table below are based on historical (energy price arbitrage), projected (RNS charges) or mixture of historical and projected costs (transmission and distribution infrastructure).

	(a)	(b)			(c)		
(1)		AESC 2021			AESC 2024		
(2)		2024	2025	2026	2024	2025	2026
(3)	**Energy**	0.64	0.62	0.68	1.26	1.32	1.14
(4)	**Energy DRIPE**	0.03	0.03	0.03	0.02	0.02	0.02
(5)	Energy price arbitrage (applies to batteries only)	12.73	12.90	13.08	12.73	12.90	13.08
(6)	**Capacity**	69.11	71.93	73.97	30.10	44.49	66.30
(7)	**Capacity DRIPE**	21.79	22.44	23.12	37.14	78.49	132.46
(8)	RNS	38.50	40.75	43.50	38.50	40.75	43.50
(9)	Transmission infrastructure	13.40	13.58	13.76	13.40	13.58	13.76
(10)	Distribution infrastructure	120.00	121.62	123.26	120.00	121.62	123.26
(11)	Total for BESS	275.53	283.23	290.69	251.87	311.83	392.36
(12)	Total for Thermostats	263.47	270.98	278.33	240.42	300.27	380.44
(13)	Total for the rest (non-Thermostats and BESS)	262.80	270.32	277.61	239.14	298.93	379.28

Prepared by or under the supervision of: Carrie Gill and Lado Kurdgelashvili

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Division 1-25
Avoided Transmission and Distribution

Request:

Rhode Island Energy has proposed looking at system specifics to allocate capital expenditures going forward (for example, the proposed capital spend for system reliability improvements based on CEMI-4 analysis). Does RIE propose to analyze its system for specific locational (load-specific) needs? For example, will RIE look at locational distribution system capacity constraints in determining whether it is applying an appropriate avoided cost estimate to a specific location?

Response:

While the level of detail for regulatory filings may change, the Company has always looked at system specific details to determine specific projects. As described in the response to Division 1-8, state-wide programs that do not have a specific locational component and are designed for homogenous, geographically unconstrained participation use state-wide homogenous factors.

Therefore, no, the Company is not proposing this level of locational need analysis or locational program design for ConnectedSolutions in 2024-2026. In fact, RI Energy cannot propose specific locational analysis for ConnectedSolutions as this type of locational use case and value requires a level of sensing, control, and communications on the electric system that the Company does not currently have. The Company does consider this type of locational use case and value in its non-wires solutions protocol where the non-wires solution would be expected to establish the necessary localized sensing, control, and communication needs. This type of locational use case and value can be implemented in the future following requisite grid modernization investments (e.g., ADMS and DERMS) with the agreement of stakeholders that this will limit customer participation.

Division 1-26

Avoided Transmission and Distribution

Request:

Does RIE plan to implement a locational demand response program to resolve specific feeder capacity constraints as opposed to a system wide program?

Response:

No, the Company is not proposing to implement a locational demand response program to resolve specific feeder capacity constraints in this SRP Investment Proposal. Such a proposal requires ADMS and DERMS; the Company does plan to employ distributed energy resources to manage feeder constraints once ADMS and DERMS are installed.

Division 1-27
Avoided Transmission and Distribution

Request:

How does the Company's estimate of avoided distribution infrastructure compare to bids received for non-wires alternatives (where NWA costs are calculated by project cost/kW reduction)?

Response:

The Company does not consider a comparison between its avoided distribution infrastructure cost estimates (or the planning value – please refer to the Company's response to DIV 1-1) and specific bids received for non-wires solutions to be appropriate.

First, bids received for non-wires solutions are likely biased (in a statistical sense of the word) because of the specific attributes of opportunities that filter projects for which we may receive bids.

Second, no non-wires solutions which satisfied the technical need requirements have advanced because all bids have been more costly than the wires solution, which would bias the magnitude of non-wires bids upwards.

Third, the system-wide avoided distribution cost estimates (and the planning value used) are based on large sample sizes, so are appropriate representations of average costs. The pool of bids received for non-wires solutions, in addition to likely being statistically biased, form a very small sample, which risks not having large enough sample size to trend toward average.

Division 1-28

Avoided Transmission and Distribution

Request:

Load growth projections for the next ten years are less than 1% per year; and over the last ten-year period, have shown a normalized trend downward (Rhode Island Energy Peak Forecast). Considering this, has there been any consideration for the potential for demand response programs to be ineffective given that peak load constraints may not materialize as soon as projected?

Response:

Please refer to the Company's response to Division 1-15; the load growth projections referenced embed the demand reductions from demand response.

Division 1-29
Avoided Transmission and Distribution

Request:

Experience has shown that projections, by the nature of changes in the assumptions underlying them, are subject to error. That said, has Rhode Island Energy considered introducing any modeling for uncertainty in its analyses?

Response:

Yes, accounting for uncertainty is the Company's impetus for using a planning value of avoided distribution cost instead of the 2024 avoided distribution infrastructure cost estimate, as well as the general practices of relying more on estimates than on point values and using precision to the ones or tens place rather than to the hundredths place (e.g., using $170 instead of $174.56) in program design. The Company is open to and hopes to integrate further measures of uncertainty into its modeling in future proposals and would be very interested in working with the Division and other stakeholders in doing so.

Prepared by or under the supervision of: Carrie Gill

Division 1-30
Avoided Transmission and Distribution

Request:

In some cases, demand response programs have been successful enough that they have had to be curtailed or that incentive payments have had to be scaled back. Has RIE considered this scenario? *NOTE: Some areas have achieved saturation rates in their demand reduction programs that they have had to curtail them or reduce the incentive payments as the incremental load reductions are no longer cost effective. For example, California residential PV programs.*

Response:

The Company has and continues to consider the scenario in which there is more interest in program participation than the program budget allows. The Company recognizes that decreasing incentive rates and limiting program enrollment are two ways in which to match program costs with program budgets. The Company will continue to evolve its incentive rates and program enrollment rules to achieve the best balance between avoided electric bill costs and program continuity, in alignment with the Least-Cost Procurement Standards.

The Company has also proposed to pursue the new Voluntary DR Pathway. Through this pathway we seek to engage and motivate as many customers as possible to voluntarily conserve energy in response to peak events. The 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.

Prepared by or under the supervision of:
Allison Archambault, Brett Feldman, Carrie Gill, and Jessica Reno

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Division 1-31

**DIVISION 1-31 WAS INADVERTENTLY INCLUDED IN THE NUMERICAL ORDERING OF DIVISION SET 1 ISSUED ON MARCH 11, 2024.
NO RESPONSE IS NEEDED FROM THE COMPANY TO DIVISION 1-31.**

Division 1-32

Avoided DRIPE (Demand Reduction Induced Price Effect) and Capacity Cost

Request:

Are capacity DRIPE ($20/kW) and avoided capacity costs in general ($70/kW) estimated as a true long-term avoided cost based on the cost of capacity additions or as an avoided cost based on the short-term (constrained) capacity market?

Response:

The forecast capacity prices are based on the results in recent auctions and expected changes in demand, supply, and market rules. These prices are applied differently for cleared resources, and uncleared demand response (measures that are not submitted into or otherwise do not clear in the ISO New England Forward Capacity Market ("FCM")). Capacity DRIPE captures the impact on electricity bills due to reductions in electric capacity prices. Both uncleared capacity and capacity DRIPE utilize a "phase-in" and "phase-out" schedule that approximates how the impacts of these resources are indirectly captured in the development of inputs to ISO New England's FCM. Therefore, calculated capacity DRIPE ($20/kW) and avoided capacity costs in general ($70/kW) capture a long-term avoided capacity cost.

Prepared by or under the supervision of: Lado Kurdgelashvili

Division 1-33

Avoided DRIPE (Demand Reduction Induced Price Effect) and Capacity Cost

Request:

Has Rhode Island Energy considered any effects of being able to dispatch consumer-owned Distributed Generation in its analyses?

Response:

Rhode Island Energy does not currently have the ability to dispatch consumer-owned Distributed Generation; therefore, the Company did not consider its effects. The Company intends to consider the effects of dispatching consumer-owned Distributed Generation when it has deployed requisite technologies, like ADMS and DERMS, to do so.

Prepared by or under the supervision of: Ryan Constable

Division 1-34

Avoided Regional Network Service (RNS) Charge

Request:

Please provide any estimates of ISO-NE RNS charges going forward.

Response:

The estimated annual ISO-NE RNS charges ($/kW-Yr) are shown in the below table. RNS charges are charged monthly. Monthly charges are one twelfth of the annual charges.

	(a)	(b)
	Start Date	**RNS Charge ($/kW-Yr)**
(1)	1/1/2024	154
(2)	1/1/2025	163
(3)	1/1/2026	174
(4)	1/1/2027	185
(5)	1/1/2028	196

Data Source: RNS Rate Forecast Overview. NEPOOL RC/TC Summer Meeting. Slide 3. July 18, 2023. URL: https://www.iso-ne.com/static-assets/documents/2023/07/a03_2023_07_18_19_rc_tc_rns_rate_forecast.pdf

Prepared by or under the supervision of: Lado Kurdgelashvili

Division 1-35
Avoided Regional Network Service (RNS) Charge

Request:

Please provide the actual ISO-NE RNS charges for the most recent 20-year period.

Response:

The actual ISO-NE RNS charges for the most recent 20-year period are provided in the table below.

	(a)	(b)	(c)
	Start Date	RNS Charge ($/kW-Yr)	Data Source
(1)	6/1/2004	16.81	1
(2)	6/1/2005	18.88	1
(3)	6/1/2006	26.31	1
(4)	6/1/2007	27.90	1
(5)	6/1/2008	43.85	1
(6)	6/1/2009	59.95	1
(7)	6/1/2010	64.83	1
(8)	6/1/2011	63.87	1
(9)	6/1/2012	75.25	1
(10)	6/1/2013	85.32	1
(11)	6/1/2014	89.80	1
(12)	6/1/2015	98.70	2
(13)	6/1/2016	104.10	2
(14)	6/1/2017	111.96	2
(15)	6/1/2018	110.43	2
(16)	6/1/2019	111.94	2
(17)	6/1/2020	129.26	2
(18)	6/1/2021	140.98	2
(19)	1/1/2022	142.78	2
(20)	1/1/2023	141.64	2
(21)	1/1/2024	154.35	2

Data Sources:

1. RNS Rates Effective June 1, 2016. Slide 22. URL: https://www.iso-ne.com/static-assets/documents/2016/08/2016_08_09_10_tc_a02_fct.pptx
2. RNS Rate Effective January 1, 2024. Slide 13. URL: https://www.iso-ne.com/static-assets/documents/2023/07/a03_1_pto_ac_notification_of_rns_rates.pdf

Prepared by or under the supervision of: Lado Kurdgelashvili

Division 1-36
Improved Reliability

Request:

Please confirm that RIE did not include the benefits value of reliability, previously estimated at $20/kW and discuss the pros and cons in making this decision.

Response:

Confirmed. The Company estimates the value of peak demand reduction at the level at which our customers would otherwise pay to serve that unit of demand during peak. Increase system reliability will not reduce customer utility bills, so it would not be appropriate to include reliability value in program design or in the proposed performance incentive mechanism.

Division 1-37
Improved Reliability

Request:

If reliability benefits were included, were they calculated using the DOE ICE Calculator? If so, please provide the inputs to the ICE model. If not, please explain how this estimate was derived.

Response:

Reliability benefits were not included in program design or in the proposed performance incentive. The Company only included reliability value in the societal benefit-cost assessment; reliability values are sourced from the AESC, not the ICE calculator.

Division 1-38
Benefit-Cost Analysis

Request:

Please provide the results of the underlying regression analyses for equation 4 on page 232 of the AESC 2024 report with all regression derived estimates, including standard deviations, R-square statistics and F-statistics.

Response:

The Company does not have the results of the underlying regression analyses in the 2024 AESC, as these analyses were prepared by Synapse Energy Economics, Inc. as part of the AESC 2024 update.

Division 1-39
Benefit-Cost Analysis

Request:

Please provide a comparison of the of the AESC Capacity DRIPE estimates for 2021 and 2024 and provide an explanation of the differences for each of the three-year period 2024 to 2026.

Response:

Capacity DRIPE estimates for 2021 and 2024 are based on Rhode Island intrazonal (zone-on-zone) uncleared capacity DRIPE values estimated based on AESC 2021 and AESC 2024, respectively. According to AESC methodology, several factors impact intrazonal capacity DRIPE values including Zonal Demand, Price Shift, Reserve Margin, Measure Life, and when the measure is deployed.

- Zonal Demand represents capacity requirements for Rhode Island's load zone.

- The "price shift" of capacity refers to how much the price of capacity (measured in $/kW-year per MW) changes in response to changes in demand. Depending on where demand crosses the supply curve, the clearing price will have a different associated price shift. The shallower the line segment, the lower the price shift's value is. Conversely, steeper line segments produce higher price shifts.

- Reserve Margin represents the planning reserve margin above Net Installed Capacity Requirement (Net ICR)[1].

- Measure Life is the duration of the demand response measure expressed in years.

Under current Forward Capacity Market (FCM) the prices are set three years in advance of a capacity commitment period, and because there is a lag in terms of when changes to load appear in the load forecast used for a capacity auction, AESC 2021 assumes that benefits from uncleared capacity do not start until five years after their installation date. AESC 2024 assumes ISO New England adopts a prompt auction structure in 2028. Under the prompt market, the phase-in timeline is accelerated by three years relative to an FCM (three-year forward market) and, thus, the phase-in would begin just two years after the installation of the measure. As a result, under

[1] ICR is the minimum level of (installed) capacity required to meet the reliability requirements defined for the New England Control Area. The net ICR (which is equal to the ICR minus the Hydro-Québec Interconnection Capability Credits [HQICCs]) is the target amount of capacity that the ISO procures through the Forward Capacity Market (FCM) to ensure system reliability.

Division 1-39, page 2
Benefit-Cost Analysis

AESC 2024, some of the previous market benefits calculated through the AESC 2021 methodology will be lost. However, these losses are not as substantial compared to the effect of updated Zone on Zone (ZoZ) Price Shift values, which have significant impacts on Uncleared Capacity DRIPE values under AESC 2024.

The table below provides summary results in nominal dollars of unclear Capacity DRIPE estimates for 2021 and 2024.

Uncleared Capacity DRIPE, $/kW (Nominal $)

	(a)	(b)	(c)	(d)
(1)	Report	2024	2025	2026
(2)	AESC 2021	$21.79	$22.44	$23.12
(3)	AESC 2024	$37.14	$78.49	$132.46

For the calculations, the Company is also providing Attachment DIV 1-39 as an Excel file.

Division 1-40
Benefit-Cost Analysis

Request:

Please provide an estimate of the summer generation component of the Avoided Bill Cost under a scenario where all of the RIE consumers have opted for competitive supply.

Response:

The summer generation component of the Avoided Bill Cost represents uncleared capacity savings. Uncleared capacity refers to load reduction measures that do not participate in Forward Capacity Auction. This is the case in this program; there would be no difference for this value for different levels of consumers opting for competitive supply (Summer Gen is independent of competitive supply).

Division 1-41

Benefit-Cost Analysis

Request:

In the Tab titled "Summary" in Schedule 2 – Benefit-Cost Assessment Model, please provide a detailed description of the derivation of the "Intrastate RI Test Benefits (Excluding Economic)" for 2024.

Response:

This column is a holdover from the previous version of the spreadsheet; this column calculated intrastate benefits by subtracting interstate benefits from all benefits from the original "Benefits" Tab (which included intrastate and interstate benefits). In the final version of the spreadsheet, the Benefits Tab was split into two tabs (the tab named "Benefits" calculates intrastate benefits and the tab named "Benefits2" calculated all benefits). Thus, the original intention of this column was to show "Intrastate RI Test Benefits (Excluding Economic)", which is already shown in the "RI Test Benefits (Excluding Economic)" Column. Therefore, this column is no longer needed.

Division 1-42
General

Request:

How does RIE plan to assess the effectiveness of each of its pathways?

Response:

The Company plans to assess the effectiveness of each of its pathways based on (1) units of regional coincident peak demand reduction achieved per pathway and (2) cost to procure each unit of regional coincident peak demand reduction achieved per pathway.

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.

___________________________________ March 21, 2024
Joanne M. Scanlon Date

Docket No. 24-06-EE – Rhode Island Energy System Reliability Procurement ("SRP") Investment Proposal for Electric Demand Response 2024-2026 – ConnectedSolutions
Service list 3/18/2024

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