Jennifer Brooks Hutchinson
Senior Counsel
PPL Services Corporation
JHutchinson@pplweb.com

280 Melrose Street
Providence, RI 02907
Phone 401-316-7429

Rhode Island Energy™
a PPL company

June 25, 2026

VIA ELECTRONIC MAIL AND HAND DELIVERY

Stephanie De La Rosa, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 25-45-GE – The Narragansett Electric Company d/b/a Rhode Island Energy Application for Approval of a Change in Electric and Gas Base Distribution Rates Pursuant to R.I. Gen. Laws §§ 39-3-10 and 39-3-11
Responses to Record Requests (Batch 1)

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), I am enclosing the Company's responses to the Public Utilities Commission's Record Requests, issued during the evidentiary hearings, in the above-referenced matter. In this transmittal, the Company is providing the following responses to Record Requests: RR 1, RR 4, RR 18, RR 27, RR 29, RR 30, RR 47, and RR 61.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-316-7429.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures

cc: Docket No. 25-45-GE Service List

Record Request No. 1

Request:

What percentage of the gas revenue requirement in RY 1 is allocated to decoupled classes in this case?

Response:

Please see Attachment RR-1 for the percentage of the proposed Rate Year 1 gas revenue requirement increase (89.99%; Cell (c)(10)) and proposed Rate Year 1 total gas revenue requirement (88.90%; Cell (e)(10)) as presented in the Rebuttal Testimony of Company Witness Blazunas allocated to decoupled classes.

Prepared by or under the supervision of: Peter Blazunas

Line No.	Rate Class (a)	Type (b)	% of RY1 Gas Revenue Requirement Increase (c)	RY1 Gas Proposed Revenue (d)	% of RY1 Gas Proposed Revenue (e)	
(1)	Residential Non-Heating	Decoupled	1.97%	$ 6,939,622	1.57%	
(2)	Residential Heating	Decoupled	67.45%	$ 298,997,549	67.57%	
(3)	C&I Small	Decoupled	11.31%	$ 39,863,127	9.01%	
(4)	C&I Medium	Decoupled	9.26%	$ 47,551,195	10.75%	
(5)	LLF Large	Non-Decoupled	4.02%	$ 20,691,970	4.68%	
(6)	HLF Large	Non-Decoupled	1.48%	$ 7,547,015	1.71%	
(7)	LLF XL	Non-Decoupled	1.34%	$ 4,650,109	1.05%	
(8)	HLF XL	Non-Decoupled	3.17%	$ 16,227,477	3.67%	
(9)	**Total**		**100.00%**	**$ 442,468,063**	**100.00%**	**=SUM[(1):(8)]**
(10)	Decoupled Rate Classes		89.99%		88.90%	**=SUM[(1):(4)]**
(11)	Non-Decoupled Rate Classes		10.01%		11.10%	**=SUM[(5):(8)]**
(12)	**Total**		**100.00%**		**100.00%**	**= (10) + (11)**

Notes:

(c) Refer to Schedule PRB-1R(c)-Gas, Page 1 of 2, Line (41)

(d) Refer to Schedule PRB-1R(c)-Gas, Page 2 of 2, Column (d), Lines (11) to (18)

(e) For Line (1): Column (d), Line (1), divided by Column (d), Line (9); and so on.

Record Request No. 4

Request:

Please provide from Docket No. 22-42-NG and SB-2021-04, any documentation that advised the PUC and/or the EFSB that three new FTEs would be required.

Response:

In EFSB Docket SB-2021-04, witnesses Jeffrey Montigny and Brian Kirkwood compare the annual cost to operate the LNG facility at Old Mill Lane using Company-owned equipment and employees compared to contracted equipment and services, but their statements do not specify whether new employees would be required:

- Attachment RR-4-1:
  - Jeffrey Montigny Prefiled Testimony to EFSB Docket No. SB-2021-04 dated September 8, 2023, Bottom of Page 5 (Page 13 of the PDF)
  - Brian Kirkwood Prefiled Testimony to EFSB Docket No. SB-2021-04 dated September 8, 2023, Pages 12 and 13, Attachment BKK-1 (Pages 40, 41, 56, and 57 of the PDF)
- Attachment RR-4-2:
  - Brian Kirkwood Hearing Transcript to EFSB Docket No. SB-2021-04, dated April 30, 2024, Pages 20 and 21.

In RIPUC Docket No. 22-42-NG the Company's response to PUC 1-13, Page 2 the Company states the need to hire employees, but it does not provide the number of employees (see Attachment RR-4-3).

Prepared by or under the supervision of: Michele Leone

Exhibit No. TNEC-17

THE NARRAGANSETT ELECTRIC COMPANY
EFSB DOCKET NO. SB-2021-04
RE: AQUIDNECK ISLAND GAS RELIABILITY PROJECT
WITNESS: JEFFREY A. MONTIGNY
SEPTEMBER 8, 2023

PRE-FILED DIRECT TESTIMONY

OF

JEFFREY A. MONTIGNY

With respect to equipment purchase, updated pricing for new equipment has recently been obtained. The previous estimate that the Company provided to the Public Utilities Commission in connection with this proceeding was based on the cost to purchase the Cumberland equipment.

As described in Mr. Kirkwood's testimony, the new equipment for Old Mill Lane would be nearly identical to the recently purchased Cumberland equipment with a few enhancements to reduce noise, monitor emissions, increase operability, and refine operator controls. The estimated cost to purchase new equipment for the Old Mill Lane Project is approximately $12.5 million. Purchasing the equipment is more cost effective for the Company as mentioned previously and also gives the Company more control by having new and modern equipment on hand that is correctly sized and fit for use, as opposed to rental equipment that may not be available or in the condition acceptable to the Company. The new equipment is also expected to operate more quietly and, with the addition of sound mitigation walls and blankets, meet the local noise ordinance requirements during the vaporization operation. It should be noted that thus far there has been no purchase of new equipment for this Project. It should also be noted that the annual cost for Rhode Island Energy to operate the winter operation with Company owned equipment and Company employees is estimated at $815,000, which is less than the $1.84 million cost for leased equipment and contracted staffing services mentioned above.

V. <u>Construction Practices and Schedule</u>

Q. Please describe the construction sequence for the Project.

A. The construction sequence for the Project includes site preparation and limited vegetation clearing, soil erosion and sedimentation controls, and facility construction as more specifically described in Section 3.2.1 of the Siting Report.

Q. What is the construction schedule for the Project?

A. The schedule depends on the time of year that the Project is approved by the Siting Board. Construction of the Project is expected to take approximately nine months of construction time, which would most likely be split into two spring / summer construction seasons due to the necessity to stop construction to allow for winter LNG operation set up. It should also be noted that any back up LNG support work for Enbridge projects (new main installation / inspections) could also affect the construction schedule. Saying that, limited construction such as vegetation removal and/or grading could occur during the winter months as long as it does not interfere with the winter operation which spans between December and March.

THE NARRAGANSETT ELECTRIC COMPANY
EFSB DOCKET NO. SB-2021-04
RE: AQUIDNECK ISLAND GAS RELIABILITY PROJECT
WITNESS: BRIAN K. KIRKWOOD
SEPTEMBER 8, 2023

PREFILED DIRECT TESTIMONY

OF

BRIAN K. KIRKWOOD

electrical cable installation, emergency generator setup, office trailer setup, and restroom facility setup. After all equipment is setup, it will take approximately two days to cooldown the equipment and fill with LNG. As with the previous scenarios this period can be reduced if the operation and delivery trailers extended outside normal business hours. Using Company employees to operate the equipment would ensure that the available staffing is required as there is no certainty with the availability of contracting personnel unless a contract is in place to reserve labor availability.

Response times and risks for the Company to mobilize owned equipment from offsite during the winter heating season would be the same as response c. The required time would still be greater than the ability to accurately forecast the weather and customer demand for peak shaving purposes. To peak shave effectively, the equipment would need to be mobilized onsite, fully setup, and tested. This scenario is not capable of providing reliability services to the single feed pipeline unless LNG is stored onsite with personnel immediately available to operate.

Q. Can you provide a detailed analysis of the financial justification for purchasing equipment, including a summary of the estimated rental costs and how those changed, if at all, over the past few years?

A. The Company has experienced rental costs that have increased over 60 percent when compared with the previous rental contract rates. Equipment with higher vaporizations rates is not readily available and the Company is subject to demand pricing for the required equipment that is needed to serve our customers. The Company performed a cost analysis to assess the viability of purchasing similar equipment and operating with Company employees instead of contracted employees. The Company's revised cost analysis is set forth in Attachment BKK-1 and includes the most recent known figures for equipment purchase and rental costs. The analysis concluded that it would take approximately six (6) years to recover the initial cost of purchasing similar equipment before the total operating costs (equipment and labor) would be significantly lower. When the scheduled offseason outages to support pipeline transmission projects are factored in, it will only take approximately four (4) years to recover the initial purchase costs. Current operating costs are recovered through the Company's Gas Cost Recovery Factor and the Company would propose to recover the cost of purchased equipment through the Infrastructure, Safety and Reliability plan. After year six (6) and during subsequent years, the Company would be providing its customers with the same services at a much lower cost.

Additionally, the purchased equipment will have additional benefits for customers over the current contracted equipment. Vaporizers will be of higher vaporization rates (two 750 MSCFH vaporizers instead of one 500 MSCFH and one 650 MSCFH vaporizer), have redundant glycol circulation pumps, quieter due to foam insulation and VFD blower motors, more efficient in operation, and utilize ultra-low NOx burners (an advantage over the current 650 MSCFH and 500 MSCFH vaporizer). Storage units will have increased reliability with each unit having a vaporization pump and unit transfer pump, will be able to operate at higher pressure, and the same number of storage vessels will hold more LNG to reduce

OML LNG

Equipment cost: 12.5 Million - (2) 750 MSCFH Vaporizers & (6) Smart Storage Queens, Including 12.5% contigency

Breakeven with 1 extra mobilization

Year	Contractor Service	Cost	Additional RIE Cost to current operation	Cost	Running Cost	Breakeven Cost	Comments
1	Seasonal Service Operation	-1,368,000	Labor (less current costs)	300,000			
	Out of season service Operation	-474,500	O&M	40,000			
	Annual Cost	**-1,842,500**	Annual Cost	**340,000**	**-1,502,500**	**10,985,000**	
2	Seasonal Service Operation	-1,368,000	Labor (less current costs)	300,000			
	Out of season service Operation	-474,500	O&M	40,000			
	Annual Cost	**-1,842,500**	Annual Cost	**340,000**	**-3,005,000**	**9,482,500**	
3	Seasonal Service Operation	-1,710,000	Labor (less current costs)	300,000			Contract cost increase 25%
	Out of season service Operation	-593,125	O&M	40,000			
	Annual Cost	**-2,303,125**	Annual Cost	**340,000**	**-4,968,125**	**7,519,375**	
4	Seasonal Service Operation	-1,710,000	Labor (less current costs)	300,000			
	Out of season service Operation	-593,125	O&M	40,000			
	Annual Cost	**-2,303,125**	Annual Cost	**340,000**	**-6,931,250**	**5,556,250**	
5	Seasonal Service Operation	-1,710,000	Labor (less current costs)	300,000			
	Out of season service Operation	-593,125	O&M	40,000			
	Annual Cost	**-2,303,125**	Annual Cost	**340,000**	**-8,894,375**	**3,593,125**	
6	Seasonal Service Operation	-1,710,000	Labor (less current costs)	300,000			
	Out of season service Operation	-593,125	O&M	40,000			
	Annual Cost	**-2,303,125**	Annual Cost	**340,000**	**-10,857,500**	**1,630,000**	
7	Seasonal Service Operation	-1,710,000	Labor (less current costs)	300,000			Contract cost increase 25%
	Out of season service Operation	-593,125	O&M	40,000			
	Annual Cost	**-2,303,125**	Annual Cost	**340,000**	**-12,820,625**	**-333,125**	**Cost savings to customers**

OML LNG

Equipment cost: 12.5 Million - (2) 750 MSCFH Vaporizers & (6) Smart Storage Queens, Including 12.5% contigency

Breakeven with 2 extra mobilization

Year	Contractor Service	Cost	Additional RIE Cost to current operation	Cost	Running Cost	Breakeven Cost	Comments
1	Seasonal Service Operation	-1,368,000	Labor (less current costs)	300,000			
	Out of season service Operation	-949,000	O&M	40,000			
	Annual Cost	**-2,317,000**	Annual Cost	**340,000**	**-1,977,000**	**10,510,500**	
2	Seasonal Service Operation	-1,368,000	Labor (less current costs)	300,000			
	Out of season service Operation	-949,000	O&M	40,000			
	Annual Cost	**-2,317,000**	Annual Cost	**340,000**	**-3,954,000**	**8,533,500**	
3	Seasonal Service Operation	-1,710,000	Labor (less current costs)	300,000			Contract cost increase 25%
	Out of season service Operation	-1,186,250	O&M	40,000			
	Annual Cost	**-2,896,250**	Annual Cost	**340,000**	**-6,510,250**	**5,977,250**	
4	Seasonal Service Operation	-1,710,000	Labor (less current costs)	300,000			
	Out of season service Operation	-1,186,250	O&M	40,000			
	Annual Cost	**-2,896,250**	Annual Cost	**340,000**	**-9,066,500**	**3,421,000**	
5	Seasonal Service Operation	-1,710,000	Labor (less current costs)	300,000			
	Out of season service Operation	-1,186,250	O&M	40,000			
	Annual Cost	**-2,896,250**	Annual Cost	**340,000**	**-11,622,750**	**864,750**	
6	Seasonal Service Operation	-1,710,000	Labor (less current costs)	300,000			
	Out of season service Operation	-1,186,250	O&M	40,000			
	Annual Cost	**-2,896,250**	Annual Cost	**340,000**	**-14,179,000**	**-1,691,500**	**Cost savings to customers**

STATE OF RHODE ISLAND
ENERGY FACILITY SITING BOARD
DOCKET NO. SB-2021-04
---x
IN RE: THE NARRAGANSETT ELECTRIC COMPANY d/b/a RHODE ISLAND ENERGY PORTABLE LNG VAPORIZATION PROJECT, OLD MILL LANE, PORTSMOUTH, RI
---x
HEARING
DATE: Tuesday, April 30, 2024
TIME: 10:00 a.m.
LOCATION:
Energy Facility Siting Board
89 Jefferson Boulevard
Warwick, Rhode Island 02888
JOB No.: J11242597

Before The Siting Board:
Ronald T. Gerwatowski, Chairman
Meredith Brady, Board Member
Terrence Gray, Board Member

Patricia Lucarelli, Siting Board Counsel

A P P E A R A N C E S
ON BEHALF OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A RHODE ISLAND ENERGY:
GEORGE WATSON, ESQUIRE
STEVE BOYAJIAN, ESQUIRE
Robinson & Cole
One Financial Plaza
Providence, Rhode Island 02903
gwatson@rc.com
sboyajian@rc.com
(401) 709-3300

ON BEHALF OF THE CONSERVATION LAW FOUNDATION:
JAMES CROWLEY, ESQUIRE
Conservation Law Foundation
235 Promenade Street, Suite 560
Providence, Rhode Island 02908
jtc2147@columbia.edu
(401) 228-1905

APPEARANCES (Cont'd.)

FOR THE ATTORNEY GENERAL:
NICHOLAS VAZ, ESQUIRE
Department of Attorney General
150 South Main Street
Providence, Rhode Island 02903
nvaz@riag.ri.gov
(401) 274-4400

ON BEHALF OF THE TOWN OF MIDDLETOWN:
MARISA DESAUTEL, ESQUIRE
Desautel Browning Law
38 Bellevue Avenue, Suite B
Newport, Rhode Island 02840
marisa@desautelbrowning.com
(401) 477-0023

ON BEHALF OF THE TOWN OF PORTSMOUTH:
KEVIN GAVIN, ESQUIRE
Law Office of Kevin P. Gavin
31 Harrington Avenue
Portsmouth, Rhode Island 02871
(401) 662-2520
kevingavinlaw@gmail.com

APPEARANCES (Cont'd.)

ON BEHALF OF THE TOWN OF PORTSMOUTH:
TERENCE TIERNEY, ESQUIRE
232 John Dyer Road
Little Compton, Rhode Island 02837
(401) 316-4566
tierneylaw@yahoo.com

ON BEHALF OF THE DIVISION OF PUBLIC UTILITIES & CARRIERS ADVOCACY SECTION CONSERVATION LAW FOUNDATION:
MARGARET HOGAN, ESQUIRE
Hogan & Hogan
128 Auburn Drive
Charlestown, Rhode Island 02813
mhoganesq@verizon.net
(401) 677-4488

ALSO PRESENT:
Brian Kirkwood, The Narragansett Electric Company d/b/a Rhode Island Energy
Brandon Flynn, The Narragansett Electric Company d/b/a Rhode Island Energy
Christopher Stutz, The Narragansett Electric Company d/b/a Rhode Island Energy

ALSO PRESENT: (Cont'd.)

Jeffrey Montigny, The Narragansett Electric Company d/b/a Rhode Island Energy
Brett Feldman, The Narragansett Electric Company d/b/a Rhode Island Energy
Tyler Onley, The Narragansett Electric Company d/b/a Rhode Island Energy

C O N T E N T S

E X H I B I T S

EXHIBIT	DESCRIPTION	MARKED	ADMITTED

(There were no exhibits identified during this proceeding.)

P R O C E E D I N G S (Cont'd.)
MR. GERWATOWSKI: All right. We'll go back on the record.
DIRECT EXAMINATION
MR. GERWATOWSKI: And -- and we're going to end this by 2:00. So I have some follow-ups from -- from some of the questions here. And I have some questions that I had on my list.
First, I don't remember who was answering the question. I think it might have been Mr. Flynn or Mr. Stutz on PUC3-3, which was Exhibit TNEC 55, I think. He was talking about what happened on February 3rd and 4th of 2023. And the response -- and they vaporized that day.
Now, it's my understanding in reading that, that was really an example of -- of encountering the capacity constraint issue. Is that correct? That was not the vulnerability issue, right?
MR. FLYNN: This is Brandon. Yes, that's correct.
MR. GERWATOWSKI: Okay. Good. Thanks. Now, as a response to EFSB 2-4. It was both a confidential and redacted version. I don't know if that's something that you can -- I think this would be, Mr. Flynn, that -- that you'd answer this. Do -- can you

pull that up?
MR. FLYNN: Yes.
MS. LUCARELLI: Mr. Chairman, do you have an exhibit number on that document, or no? It may be on -- it may be in the (crosstalk) --
MR. GERWATOWSKI: I'm sure it's -- it -- it was one of the -- it was some -- it was from Siting Board Set 2. And it was (crosstalk) --
MS. LUCARELLI: So it might -- it -- it could be Exhibit (crosstalk) --
MR. GERWATOWSKI: If you have the (crosstalk) --
MS. LUCARELLI: -- 34.
MR. GERWATOWSKI: What's that?
MS. LUCARELLI: TNEC 34, I believe you had (crosstalk) --
CHAIRMAN: Okay. Did you -- have you pulled it up yet?
MR. FLYNN: Was it -- this is Brandon. Did you say TNEC 34?
MS. LUCARELLI: 34, I believe.
MR. FLYNN: Thank -- thank you.
MS. LUCARELLI: Is that --
MR. GERWATOWSKI: It was -- the document is labeled as EFSB 2-4, which was response to a data

request.
MR. FLYNN: Okay.
MR. WATSON: Is it okay if I present a copy to him?
MR. GERWATOWSKI: Yes. Go ahead. That would help. Yeah.
MR. WATSON: Thank you.
MR. GERWATOWSKI: In the middle paragraph of that answer -- I'll -- I'll read the whole paragraph. And then I'll come back to the question that I have.
It said -- this was sponsored by Julie Porcaro. But I think, Mr. Flynn, you adopted these.
MR. FLYNN: Yes.
MR. GERWATOWSKI: "Rhode Island Energy has expressed interest in G system enhancements to relieve the capacity vulnerability and capacity constraint. However, currently, there is no additional capacity available on this portion of the G system. As described in the company's response to EFSB 2-2, the Sakonnet River crossing would need to be increased to a 12-inch diameter pipe. And the remainder of the single line section of the G2 lateral would need to be looped with 12-inch diameter pipe back to the existing 12-inch diameter pipe, approximately 4 miles total, to relieve capacity vulnerability. And other

was some discussion that occurred in a -- in a -- in the -- a PUC docket, 2349NG, which related to the Exeter -- Exeter site. Well, I think Mr. Kirkwood and Mr. Montigny, you remember this, from a PUC docket. And -- and we saw a diagram for some improvements on that site. And one of the improvements, which you hadn't -- hadn't factored in any cost with, was a -- a 8-bay garage. And during that proceeding, I think it was stated that you needed the 8-bay garage so if the Old Mill Lane project is approved, you -- you needed to store the equipment in the 8-bay garage. And -- and that was my understanding. And it was -- but there was no cost associated with that yet.

But -- but it sounded like in the other docket, you had said that the garage is needed if you get an approval for the Old Mill Lane project.

MR. KIRKWOOD: Yes, sir. This is Brian. So this -- over the years, this project has developed. We've learned more information. The original intent was to continue leasing equipment. And -- and then we decided it was cost effective to purchase. So, in doing so, looking through this long term, this project is approved. You know, it is -- the equipment does not have to be stored indoors. But again, it just adds to the -- it reduces overall maintenance to the

equipment, if it can be sheltered.

MR. GERWATOWSKI: Okay. And again, like I said before, I'm -- I don't believe for a second that anybody was just trying to, you know, hide the pea under a cup or anything like that. I think it's probably just a regulatory misunderstanding.

If you're saying that the garage is (technical difficulty) I would be adding that to the cost as well. So somewhere the project is over 24 million, whatever that garage cost would be. If, in fact, the basis for building the garage is because you need it to store the Old Mill Lane equipment. Do you follow what I'm saying?

MR. KIRKWOOD: Yes, I do.

MR. GERWATOWSKI: And so -- okay. All right. So we're -- we're at excess of -- for what it is, we're in excess of $24,000,000, you know, with you -- if you add up all the various costs associated with doing this project out at the Old Mill Lane. That's how I'm envisioning it.

MR. KIRKWOOD: Yes, that's correct. And purchasing it.

MR. GERWATOWSKI: Okay. All right. Not sure it changes very much, but I wanted to make sure that I -- I had the -- the cost issue correct.

Now, what I would really like to do is just ask for a record request. Just so that the cost is really clear. If you can create a schedule that itemizes all of the capital costs for the project. And I don't need anything under $1,000,000. But any -- any component that's $1,000,000 or greater. Just break it down. Give us the total. If you have a -- a ballpark estimate for the -- for the garage, thinking -- that you were thinking about too. I realize that's not precise. But I'm just looking for a ballpark estimate. And then put that together. And that'll give us a -- a clearer sense of at least how I'm looking at it, what the cost is. So we can take that as a request? Okay.

Now, the -- speaking of cost schedules, Mr. Kirkwood, there was a schedule that -- that I've looked at several times. And I just didn't understand it. And it's probably because I'm used to rate schedules and -- and cost-of-service schedules, which is different from the one that you attached to your testimony.

But if you -- in -- in your direct testimony, you had Attachment BKK1 and if you could find that. But I really -- I mean, I understand what you're saying for various components. But I -- I'm lost on

-- on what you were trying to illustrate with this schedule. And -- and I -- I think I need an elementary explanation of it.

MR. KIRKWOOD: This is Brian -- Brian Kirkwood again. So this is probably not a conventional cost analysis. Excuse me. It's just to illustrate, really break it down into (technical difficulty) really is.

So if you're looking at the left-hand side, that has the -- the contracted operation. So at the time of this, you know, we had our known contracts rates, what that cost is to do that operation. In that same left-hand side, we also have the RIE cost that has the labor and security, and also the O&M for the site.

So think of it as two pieces, where we have one piece for the equipment, and the labor to operate that equipment. And we also have the company's cost to have their company personnel, security and general maintenance of the site. Those are -- sorry. Go ahead.

MR. GERWATOWSKI: Keep going. Keep going.

MR. KIRKWOOD: Yes. So I broke that down into several years. And I made an assumption of a price increase, assuming that we'd have a four-year

Page 21

contract. And that price increase has been less that we've observed over the last few years. So I was being conservative with that.

But it's -- it's a running cost of how much that costs each year, if you tally the cost of the contractor services, plus the company cost.

MR. GERWATOWSKI: And who -- and which contractor services would this relate to?

MR. KIRKWOOD: To rent the equipment, and to operate the equipment, with contracted personnel.

MR. GERWATOWSKI: So this is what it would have been if you did not buy the -- the units. That's what this is illustrating?

MR. KIRKWOOD: Exactly. And on the right-hand side, I started subtracting those costs. So if we said if we bought the equipment, we have a known fixed cost. We know what our labor would be to operate the equipment. And we know the cost to maintain the site. So I just each year subtracted what the leased cost would have been from there, to deduce that return.

MR. GERWATOWSKI: All right. Thank -- thank you for that. I -- I appreciate it. That's I just wanted to make sure I understood it.

Now on -- on page -- oh, at least -- I closed

Page 22

this. I shouldn't have. On page 16 of the testimony. Mr. Kirkwood, you had a statement that -- let me find it again. On -- on line 21, that it would save -- that the purchase would save money for customers. And I was trying to figure out how you -- how do you calculate cost -- how were you calculating cost savings? Savings compared to what? Compared to the rental? Is that what you mean?

MR. KIRKWOOD: Yes, exactly.

MR. GERWATOWSKI: Okay.

MR. KIRKWOOD: So if we proceed with purchasing, we can estimate, based on the rates that we know and everything, and the cost to operate. That after year X, we will not -- we will operate the site at a much lower cost than what we're doing right now at this moment.

MR. GERWATOWSKI: Okay. All right. I wanted to make sure which savings you were talking about.

And then, Mr. Montigny, on -- on page 9 of your testimony, you referred to lighting as being dark-sky compliant. You don't have to find it in your testimony. Because it -- the question is, I don't understand what dark-sky compliant -- dark-sky incompliant means.

MR. MONTIGNY: This is -- this is Jeff

Page 23

Montigny. So I was told that we are now dark-sky compliant, and that additional equipment was put on the lighting. But I think Brian Kirkwood may be able to answer that --

MR. GERWATOWSKI: Okay.

MR. MONTIGNY: -- in more better detail than me.

MR. GERWATOWSKI: Okay. Go ahead, Mr. Kirkwood.

MR. KIRKWOOD: Yeah, this is Brian Kirkwood. So the dark-sky -- dark-sky compliant lights, they have a shroud that prevents the light from -- the -- the hue from a flood light, going upwards or outwards. And it really directs it like a cone, directly down into the site. So when we first installed them, we didn't have those shrouds over. And based on feedback from the -- the neighborhood, we added that. And that reduced the -- the light pollution that leaves the property boundaries.

MR. GERWATOWSKI: Okay. Now I don't know who would know the answer to this. But I'm -- I'm sure it's one of the two of you, Mr. Montigny or -- or you.

So at -- at night, when -- when the -- when it's operational, is the -- is there a lot of lights

Page 24

that are constantly on, or do they just come on when -- when you operate? What's -- what's the -- what's happening with the lighting out there, I guess is what I'm asking.

MR. KIRKWOOD: So in our normal -- normal operations where we have equipment installed onsite, and we have personnel onsite, because we have equipment, we have minimal lighting. And -- and I say "minimal." And what that means is, we have utility poles around the property that has overhead light. On the pole closest to the gate station, so on the east side of the property, we have one flood light that's on at night. It's on a photocell. So it turns on, you know, at some point when the sun goes down. And turns --

MR. GERWATOWSKI: Uh-huh.

MR. KIRKWOOD: -- off at sunrise. And then we also have lighting on the restroom trailer, very small lighting that's for the stairs. And the equipment has lighting that's around chest height. It -- it does vary on the type of equipment.

MR. GERWATOWSKI: Okay. Okay.

MR. KIRKWOOD: And that's pointed down as well. So people can walk throughout the site, you know, do their security inspections, their operation

---

PUC 1-13

Request:

Referencing the purchase of the equipment,

a. Is the purchase of the equipment at $9.2 million for the winter 2023-2024 or the winter 2024-2025? (Montigny Testimony at page 5).

b. Is the purchase of the equipment in the FY 2023 Gas ISR Filing that was made by the Company on December 23, 2022?

c. Is the purchase of the equipment contingent upon EFSB approval of the Company's project proposal? Please explain.

Response:

a. The Company has not yet purchased or placed a deposit on the portable LNG equipment for the Old Mill Lane facility. The Company did, however, purchase portable LNG equipment for its Cumberland LNG facility that will go into service during calendar year ("CY") 2023 for the 2023/2024 winter heating season. The cost estimate referenced on Page 5 of Company Witness Jeffrey A. Montigny was for the purchase of equipment for the Cumberland LNG facility. The total estimated cost for the purchase of portable LNG equipment for use at Old Mill Lane is $2.51 million during CY 2023 and $9.2 million during CY 2024, for a total of $11.51 million. The difference between the 2022 $9.2 million estimate given earlier and the filed $11.51 million estimate is a contingency for an anticipated price increase because of inflation and the cost of materials. This equipment would be placed into service in CY 2025 for the 2025/2026 winter heating season.

b. The Company included the proposed purchase of portable LNG equipment for the Old Mill Lane facility in its Fiscal Year ("FY") 2024 Gas Infrastructure, Safety, and Reliability ("ISR") Plan, which was filed with the Public Utilities Commission on December 23, 2022, in Docket No. 22-54-NG. Please note- that, although the portable LNG equipment for Old Mill Lane is included in the CY 2023 and CY 2024 budgets, it would not have a customer rate impact until CY 2025 when the Company forecasts that it will be placed in service.

Prepared by or under the supervision of: Brian K. Kirkwood,
Nathan Kocon, and Jeffrey A. Montigny

PUC 1-13, Page 2

c. Ordering portable LNG equipment for Old Mill Lane is contingent upon the Energy Facility Siting Board approval of continued portable LNG operations at Old Mill Lane and Public Utilities Commission approval of the Company's FY 2024 ISR Plan. If both approvals are granted, the Company plans to place an order in CY 2023 for portable LNG equipment that will be used at Old Mill Lane. The equipment could be used at the future desired footprint, which is set back further from the street, or it can be used on the existing footprint of Old Mill Lane. Because of the long lead times for this type of equipment, it is critical that an order be placed in CY 2023. Current lead times range from six to twelve months and vary with the availability of manufacturing capacity, which is also impacted by other customer orders. The equipment purchase will require a 25% deposit in CY 2023 with targeted equipment completion in CY 2024. The planned in-service date of the portable equipment is CY 2025. Although the new owned equipment may be in the Company's possession in CY 2024, the existing leased equipment would be used for the duration of the 2024/2025 winter heating season. Then the new owned equipment would be fully set up for the 2025/2026 winter heating season. Having the new owned equipment in service is also dependent upon hiring and training Company employees to operate the site with the same services currently provided by contracted services. The portable LNG operations are critical to the reliability of gas operations on Aquidneck Island. Thus, the portable LNG equipment will be necessary to support gas operations on Aquidneck Island.

Prepared by or under the supervision of: Brian K. Kirkwood,
Nathan Kocon, and Jeffrey A. Montigny

Record Request No. 18

Request:

Please update the inflation factor.

Response:

Please see the table below for the updated inflation factors as of May 2026. The amounts were calculated in the same manner and used the same sources as the calculation in the original filing. Please see Attachment RR-18 for the calculation of the below amounts in the same format as Schedule SAB-3, Page 5 in the original filing.

Line No.	**Test Year to Rate Year 1 (a)**	**Rate Year 1 to Rate Year 2 (b)**	**Rate Year 2 to Data Year (c)**
1	6.85%	2.32%	2.24%

The Narragansett Electric Company d/b/a Rhode Island Energy
Calculation of Inflation
Occurring Between The Test Year And The Rate Year

Line No.	*Calculation of Inflation Rate:*	(a)
1		CPI-U
2	Index - Average of Test Year August 2025	131.04
3		
4	Index - Average of Rate Year July 2027	140.01
5		
6	Increase in Index From Average Of The Test Year	
7	To The Average of Rate Year	
8	**Inflation Factor %**	**6.85%**
9		
10	Source: Blue Chip Financial Forecast	
11		
12		
13		CPI-U
14	Index - Average of Rate Year July 2027	140.01
15		
16	Index - Average of Rate Year July 2028	143.26
17		
18	Increase in Index From Midpoint Of The Test Year	
19	To The Midpoint of Rate Year	
20	**Inflation Factor %**	**2.32%**
21		
22	Source: Blue Chip Financial Forecast	
23		
24		CPI-U
25	Index - Midpoint of Rate Year July 2028	143.26
26		
27	Index - Midpoint of Rate Year July 2029	146.47
28		
29	Increase in Index From Midpoint Of The Test Year	
30	To The Midpoint of Rate Year	
31	**Inflation Factor %**	**2.24%**

CPI-U - URBAN Consumer Price Index

Record Request No. 27

Request:

RIE should review the changes to the LRS cash working capital made in Docket No. 26-05-EL as a result of an ISO Settlement/Supplier issue and respond whether a similar revision to the requested case working capital should be made here. (if not, please explain).

Response:

The Company agrees that a similar revision to the requested cash working capital should be made in this filing to reflect the adjustments to LRS cash working capital in Docket No. 26-05-EL as a result of an ISO settlements/supplier match issue identified in that filing. Please refer to Attachment RR-27 for an updated lead-lag study in the same format as Schedule JSW-1-ELEC that reflects the revision. Please note that the percentages in Attachment RR-27 are the updated amounts, but the actual dollar amounts and cash working capital dollars may differ based on the final expense amounts.

Prepared by or under the supervision of: Joseph Weiss

The Narragansett Electric Company
Cash Working Capital Requirements
For The Twelve Months Ended August 31, 2025
Cash Working Capital Requirements

			CWC %			RATE YEAR		
Line No.	Description		Revenue Receipt Lag	Expense Payment (Lag)	Net Payment (Lead) Lag	Total Dollars (Company Direct)	CWC Dollars	Reference page for Total Dollars:
			(a)	(b)	(c)	(d)	(e)	(f)
1	Purchase Power		19.62%	-13.22%	6.40%	Recovered via Company Electric Retail Rate Filing		3
2	Operation & Maintenance Expense		19.62%	-8.04%	11.58%	$174,725,153	$20,238,955	4
3	Transmission		19.62%	-12.47%	7.15%	$221,897,018	$0	5
4	Federal Income Tax		19.62%	-6.12%	13.50%	$0	$0	6
	Taxes Other than Income Taxes							
5	Municipal Taxes		19.62%	-6.85%	12.77%	$40,816,333	$5,212,246	7
6	Sales and Use Tax		19.62%	-9.67%	9.95%	$1,750,741	$174,199	8
7	Gross Earnings Tax		19.62%	-11.36%	8.26%	$50,339,791	$4,158,067	9
	Payroll Taxes - Company Portion							
8	Employer Federal Unemployment		19.62%	-3.13%	16.49%	$74,586	$12,299	10
9	Employer State Unemployment		19.62%	-3.13%	16.49%	$298,343	$49,197	11
10	FICA Expense	- Weekly	19.62%	-3.12%	16.50%	$3,683,239	$607,734	12
11		- Bi Weekly	19.62%	-3.12%	16.50%	$2,656,552	$438,331	13
	Payroll Taxes and Other Withholding							
12	Employee FICA and Federal Withholding	- Weekly		0.27%	0.27%	$4,636,953	$12,520	14
13		- Bi Weekly		0.27%	0.27%	$3,344,422	$9,030	15
14	Employee State Income Tax Withholding	- Weekly		0.27%	0.27%	$2,566,953	$6,931	16
15		- Bi Weekly		0.27%	0.27%	$2,011,232	$5,430	17
16	Temporary Disability Insurance	- Weekly		0.27%	0.27%	$479,854	$1,296	18
17		- Bi Weekly		0.27%	0.27%	$333,199	$900	19
18	Total Working Capital Requirement - Distribution					**$509,614,368**	**$30,927,134**	

Line Notes

(a) Page 2, Line 26
(b) From Schedule in Column (f)
(c) Column (a) + (b)
(d) From Schedule in Column (f)
(e) Column (c) x Column (d)

The Narragansett Electric Company
Summary of Purchased Power
For The Twelve Months Ended August 31, 2025

Line No.	Description (a)	Reference (b)	CWC % (c)
1	Net CWC Percent Lag	Line 7	6.40%
2	Total Payments in year		348,703,566
3	Total Weighted Dollar Days		16,830,611,739
4	Payment Lag Days	Line 3 / Line 2	(48.27)
5	Payment Lag Days as Percent of Year	Line 4 / 365	-13.22%
6	Revenue Lag Days Percent	Page 2, Line 27	19.62%
7	Net CWC Percent Lag	Line 6 + Line 5	6.40%

The Narragansett Electric Company
Cash Working Capital Requirements
Operating & Maintenance (O&M) Summary
For The Twelve Months Ended August 31, 2025

Line No.	Cost Category (a)	Amount (b)	Lead Days (c)	Weighted Days (d) = (b) * (c)	Percentage Of total O&M	Expense Payment % (Lag)	Weighted Expense Payment %
1	Payroll-Weekly	$22,319,918	(7.96)	(177,700,887)	14.56%	-2.18%	**-0.32%**
2	Payroll-Bi Weekly	$20,376,961	(11.50)	(234,335,048)	13.29%	-3.15%	**-0.42%**
3	Variable Pay	$2,224,651	(252.50)	(561,724,261)	1.45%	-3.15%	**-0.05%**
3	Total Payroll	$44,921,529					
4							
5	Service Company Billing	$123,780,398	(38.80)	(4,802,865,104)	81%	-10.63%	**-8.58%**
6							
7	Other O&M	($15,401,924)	(48.27)	743,450,865	-10.05%	-13.22%	**1.33%**
8							
9	Total	$153,300,003		(4,059,414,239)	100%		**-8.04%**
10							
11							
12	Other O&M (Adjusted)	160,154,551					
13	Payroll Expense	(44,921,529)					
14	Service Co. Billing	(123,780,398)					
15	Uncollectibles	($6,854,548)					
16							
17							
18	Other O&M	(15,401,924)					

THE NARRAGANSETT ELECTRIC COMPANY
Cash Working Capital Requirements
Test Year Ended 08/31/2025
Purchased Power Costs

Line No.		Service Period Begin (a)	Service Period End (b)	Payment Date (c)	Lead Days (d)	Payment Amount (e)	Dollar Weighted Days (f)
1	September 2024 Routine Payment	9/1/2024	9/30/2024	10/21/2024	21	$6,454,827.50	$135,551,377.50
2	September 2024 - ARRF - LRS Expense Adjustment	9/1/2024	9/30/2024	10/21/2024	21	($659,334.96)	($13,846,034.09)
3	September 2024 Settlement A	8/1/2024	8/31/2024	10/21/2024	51	$17,267,394.01	$880,637,094.51
4	September 2024 Settlement B	5/1/2024	5/31/2024	10/21/2024	143	$185,417.17	$26,514,655.31
5	October 2024 Routine Payment	10/1/2024	10/31/2024	11/20/2024	20	$6,607,793.41	$132,155,868.20
6	October 2024 - ARRF - LRS Expense Adjustment	10/1/2024	10/31/2024	11/20/2024	20	($786,257.20)	($15,725,144.06)
7	October 2024 Settlement A	9/1/2024	9/30/2024	11/20/2024	51	$23,106,966.51	$1,178,455,292.01
8	November 2024 Routine Payment	11/1/2024	11/30/2024	12/20/2024	20	$5,693,072.67	$113,861,453.40
9	November 2024 - ARRF - LRS Expense Adjustment	11/1/2024	11/30/2024	12/20/2024	20	($867,152.35)	($17,343,047.06)
10	November 2024 Settlement A	10/1/2024	10/31/2024	12/20/2024	50	$27,267,635.96	$1,363,381,798.00
11	November 2024 Settlement B	7/1/2024	7/31/2024	12/20/2024	142	$936,405.17	$132,969,534.14
12	December 2024 Routine Payment	12/1/2024	12/31/2024	1/20/2025	20	$4,947,539.32	$98,950,786.40
13	December 2024 - ARRF - LRS Expense Adjustment	12/1/2024	12/31/2024	1/20/2025	20	($1,203,154.57)	($24,063,091.48)
14	December 2024 Settlement A	11/1/2024	11/30/2024	1/20/2025	51	$32,023,780.52	$1,633,212,806.52
15	December 2024 Settlement B	8/1/2024	8/31/2024	1/20/2025	142	($1,490,097.86)	($211,593,896.12)
16	January 2025 Routine Payment	1/1/2025	1/31/2025	2/20/2025	20	$4,934,839.79	$98,696,795.80
17	January 2025 - ARRF - LRS Expense Adjustment	1/1/2025	1/31/2025	2/20/2025	20	($1,269,406.90)	($25,388,137.93)
18	January 2025 Settlement A	12/1/2024	12/31/2024	2/20/2025	51	$40,588,400.55	$2,070,008,428.05
19	January 2025 Settlement B	9/1/2024	9/30/2024	2/20/2025	143	($426,961.29)	($61,055,464.47)
20	February 2025 Routine Payment	2/1/2025	2/28/2025	3/20/2025	20	$5,294,190.06	$105,883,801.20
21	February 2025 - ARRF - LRS Expense Adjustment	2/1/2025	2/28/2025	3/20/2025	20	($1,236,000.09)	($24,720,001.89)
22	February 2025 Settlement A	1/1/2025	1/31/2025	3/20/2025	48	$34,181,252.49	$1,640,700,119.52
23	February 2025 Settlement B	10/1/2024	10/31/2024	3/20/2025	140	($101,716.35)	($14,240,289.00)
24	March 2025 Routine Payment	3/1/2025	3/31/2025	4/21/2025	21	$5,237,536.42	$109,988,264.82
25	March 2025 - ARRF - LRS Expense Adjustment	3/1/2025	3/31/2025	4/21/2025	21	($1,307,326.72)	($27,453,861.03)
26	March 2025 Settlement A	2/1/2025	2/28/2025	4/21/2025	52	$26,110,469.26	$1,357,744,401.52
27	March 2025 Settlement B	11/1/2024	11/30/2024	4/21/2025	142	$281,825.35	$40,019,199.70
28	April 2025 Routine Payment	4/1/2025	4/30/2025	5/20/2025	20	$5,155,102.61	$103,102,052.20
29	April 2025 - ARRF - LRS Expense Adjustment	4/1/2025	4/30/2025	5/20/2025	20	($636,257.99)	($12,725,159.71)
30	April 2025 Settlement A	3/1/2025	3/31/2025	5/20/2025	50	$13,591,360.23	$679,568,011.50
31	April 2025 Settlement B	12/1/2024	12/31/2024	5/20/2025	140	$3,781,141.57	$529,359,819.80
32	May 2025 Routine Payment	5/1/2025	5/31/2025	6/20/2025	20	$1,259,974.11	$25,199,482.20
33	May 2025 - ARRF - LRS Expense Adjustment	5/1/2025	5/31/2025	6/20/2025	20	($646,509.96)	($12,930,199.27)
34	May 2025 Settlement A	4/1/2025	4/30/2025	6/20/2025	51	$13,422,633.73	$684,554,320.23
35	May 2025 Settlement B	1/1/2025	1/31/2025	6/20/2025	140	$4,518,550.43	$632,597,060.20
36	June 2025 Routine Payment	6/1/2025	6/30/2025	7/21/2025	21	$723,556.98	$15,194,696.58
37	June 2025 - ARRF - LRS Expense Adjustment	6/1/2025	6/30/2025	7/21/2025	21	($808,421.69)	($16,976,855.51)
38	June 2025 Settlement A	5/1/2025	5/31/2025	7/21/2025	51	$19,752,397.87	$1,007,372,291.37
39	June 2025 Settlement B	2/1/2025	2/28/2025	7/21/2025	143	$2,018,015.72	$288,576,247.96
40	July 2025 Routine Payment	7/1/2025	7/31/2025	8/20/2025	20	$687,030.57	$13,740,611.40
41	July 2025 - ARRF - LRS Expense Adjustment	7/1/2025	7/31/2025	8/20/2025	20	($1,242,268.36)	($24,845,367.15)
42	July 2025 Settlement A	6/1/2025	6/30/2025	8/20/2025	51	$34,981,249.08	$1,784,043,703.08
43	July 2025 Settlement B	3/1/2025	3/31/2025	8/20/2025	142	($4,485,226.99)	($636,902,232.58)
44	August 2025 Routine Payment	8/1/2025	8/31/2025	9/22/2025	22	$3,735,387.48	$82,178,524.56
45	August 2025 - ARRF - LRS Expense Adjustment	8/1/2025	8/31/2025	9/22/2025	22	($722,006.45)	($15,884,142.00)
46	August 2025 Settlement A	7/1/2025	7/31/2025	9/22/2025	53	$23,321,435.42	$1,236,036,077.26
47	August 2025 Settlement B	4/1/2025	4/30/2025	9/22/2025	145	($1,475,516.64)	($213,949,912.80)
48							
49					**48.27**	**$348,703,566**	**$16,830,611,739**

Record Request No. 29

Request:

Please provide the relevant provisions of ASC 980.

Response:

Please see Attachment RR-29 for the relevant provisions of ASC 980. The first page discusses the criteria required for an entity to be subject to ASC 980 and, therefore, be permitted to record regulatory assets (regulatory asset criteria shown on page 2). On page 1, Criterion b relates to the fact that to qualify for accounting under ASC 980, rates must be designed to recover costs and not be performance based. Pages 3 and 4 include interpretive guidance/examples from the PwC Utilities and Power Companies guide, which discusses some criteria that demonstrate when rates are cost-based or may be more alternative in nature.

ASC 980-10-15-2

980-10-15 Scope and Scope Exceptions

General

Entities

15-2 The guidance in the Regulated Operations Topic applies to general-purpose external financial statements of an entity that has regulated operations that meet all of the following criteria:

a The entity's rates for regulated services or products provided to its customers are established by or are subject to approval by an independent, third-party regulator or by its own governing board empowered by statute or contract to establish rates that bind customers.

b The regulated rates are designed to recover the specific entity's costs of providing the regulated services or products. This criterion is intended to be applied to the substance of the regulation, rather than its form. If an entity's regulated rates are based on the costs of a group of entities and the entity is so large in relation to the group of entities that its costs are, in essence, the group's costs, the regulation would meet this criterion for that entity.

c In view of the demand for the regulated services or products and the level of competition, direct and indirect, it is reasonable to assume that rates set at levels that will recover the entity's costs can be charged to and collected from customers. This criterion requires consideration of anticipated changes in levels of demand or competition during the recovery period for any capitalized costs. This last criterion is not intended as a requirement that the entity earn a fair return on shareholders' investment under all conditions; an entity can earn less than a fair return for many reasons unrelated to the ability to bill and collect rates that will recover allowable costs. For example, mild weather might reduce demand for energy utility services. In that case, rates that were expected to recover an entity's allowable costs might not do so. The resulting decreased earnings do not demonstrate an inability to charge and collect rates that would recover the entity's costs; rather, they demonstrate the uncertainty inherent in estimating weather conditions. This requirement must also be evaluated in light of the circumstances. For example, if the entity has an exclusive franchise to provide regulated services or products in an area and competition from other services or products is minimal, there is usually a reasonable expectation that it will continue to meet the other criteria. Exclusive franchises can be revoked, but they seldom are. If the entity has no exclusive franchise but has made the very large capital investment required to provide either the regulated services or products or an acceptable substitute, future competition also may be unlikely.

ASC 980-340-25-1

Contents

980-340-25 Recognition

General Note

The Recognition Section provides guidance on the required criteria, timing, and location (within the financial statements) for recording a particular item in the financial statements. Disclosure is not recognition.

General

Effects of Regulation

Recognition of Regulatory Assets

25-1 Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:

- **a** It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes.
- **b** Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost.

A cost that does not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date.

PwC Power and Utilities Guide 17.2.1

Figure UP 17-1

Evaluating whether rates are designed to recover costs of service

Factors	Indicators that rates are cost-based	Indicators that rates are other than cost-based
Rate case activity	• General rate cases occur at regular intervals or more frequently as necessary • Regulatory lag periods are not extensive and are comparable to peers	• Sustained period of no rate cases • Unusually long lag periods, causing the reporting entity to under-earn or over-earn
Rate design	• Rates are designed to recover incurred costs plus a reasonable return on rate base • Rate process incorporates actual or estimated costs (or both) in developing the revenue requirement and customer rates	• Rates are based on market or average industry costs or based on reporting entity performance (incentive-based rates) • The revenue requirement has little or no connection to the reporting entity's cost of service
Periods of alternative ratemaking (e.g., rate freezes) (UP 17.2.2.1)	• A return to cost-based regulation may be elected by the utility if the results of the alternative form of rate regulation do not provide cost recovery • Alternative rate structure is temporary or for a short period, and cause and effect is still present	• Regulator determines if and when the utility may return to cost-based regulation • Alternative rate making is in effect permanently, for a long period, or without a stated timeframe
Cost uncertainty	• Highly volatile costs (such as fuel) are recovered via a tracker or other similar recovery mechanism • Special rate cases are provided for nonrecurring, unusual, significant costs or gains (e.g., major storm damage, sale of a facility)	• The utility is required to manage volatile costs to a target; shareholders are subject to the risks and rewards of deviation from that target • No interim adjustments to rates to compensate for potentially significant losses or gains; no true-up to actual costs if amounts deviate from expected
Disallowances	• Disallowances may occur on occasion but are limited in frequency and amount • Regulator demonstrates willingness to allow recovery of incurred costs plus a return	• Frequent or recurring disallowances occur, impacting the utility's ability to recover its costs • Implementation of phase-in plans

17.2.2.1 Impact of alternative ratemaking

Evaluation of the second criterion requires additional judgment if the regulated utility is subject to any form of ratemaking that introduces uncertainty about the cause-and-effect relationship between costs and rates. Prior to the codification, paragraph 65 of FAS 71 elaborated on this point as follows:

> **Excerpt from FAS 71, paragraph 65**
>
> If rates are based on industry costs or some other measure that is not directly related to the specific enterprise's costs, there is no cause-and-effect relationship between the enterprise's costs and its revenues. In that case, costs would not be expected to result in revenues approximately equal to the costs; thus, the basis for the accounting specified in this Statement is not present under that type of regulation.

Consistent with this guidance, adoption by a regulator of any alternative forms of ratemaking, such as rate freezes, performance or incentive rates, price caps, or discounting, would call into question whether ASC 980 applies. If alternative or nontraditional forms of ratemaking are implemented, a reporting entity should carefully evaluate whether it meets or continues to meet the ASC 980-10-15-2(b) criterion.

Record Request No. 30

Request:

What are utilities around the country using for capitalization policies for software concerning dollar value thresholds?

Response:

Please see Attachment RR-30-1 and Attachment RR-30-2 for EEI survey information requests regarding software capitalization dollar value thresholds. Company names are not provided as part of these surveys.

Attachment RR-30-1

Please see the Excel version of Attachment RR-30-1.

Attachment RR-30-2

Please see the Excel version of Attachment RR-30-2.

Record Request No. 47

Request:

Please provide a draft redline A-60 tariff to reflect the Low Income Discount Rate settlement proposal.

Response:

Please see Attachment RR-47 for a draft redline A-60 tariff that reflects the Low-Income Discount Rate Settlement Proposal.

For context: the Low-Income Discount Rate tariff that is currently in effect is R.I.P.U.C. No. 2225. The annotated version that maps the current tariff into the new tariff format is provided in Exhibit RIE-17 (Schedule SAB-43, Book 14, Bates Pages 8-9). Attachment RR-47 adopts the organization as proposed in Exhibit RIE-17 and shows redlines for revisions required to reflect the Proposed Settlement.

Please also note that this draft tariff does not include further edits to the eligibility criterion described in Section 3.1.2, as contemplated in the Company's response to Division 14-1. The Company notes that it will respond to these inquiries in Record Request 50. The Company is open to further revising the Low-Income Discount Rate tariff, beyond what is included in Attachment RR-47, in whatever manner presents the right degrees of precision and clarity.

RIPUC No. 2283
Sheet 1
Canceling R.I.P.U.C. No. 2225

THE NARRAGANSETT ELECTRIC COMPANY
LOW INCOME RATE (A-60)
ELECTRIC RETAIL DELIVERY SERVICE

1. DESCRIPTION AND AUTHORITY

1.1. This tariff describes electric delivery service for residential customers pursuant to R.I. Gen. Laws § 39-2-1.

2. AVAILABILITY

2.1. Service is available under this tariff for residential customers of the Company, subject to the eligibility criteria in Section 3.

3. ELIGIBILITY

3.1. Service under this rate is available only to currently qualified customers for all domestic purposes in an individual private dwelling or an individual apartment, providing such customer meets both of the following criteria:

3.1.1. Must be the head of a household or principal wage earner; and

3.1.2. Must be presently receiving Supplemental Security Income from the Social Security Administration, be eligible for the ~~l~~Low~~-~~ I~~i~~ncome H~~h~~ome E~~e~~nergy A~~a~~ssistance P~~p~~rogram (“LIHEAP”), or one of the following from the appropriate Rhode Island agencies: Medicaid, Supplemental Nutrition Assistance Program (“SNAP”)~~Food Stamps~~, General Public Assistance or the Rhode Island Works Program (formerly known as Family Independence Program) or successor programs.

4. DEFINITIONS

4.1. “Commission” shall mean the Rhode Island Public Utilities Commission.

4.2. “Company” shall mean The Narragansett Electric Company d/b/a Rhode Island Energy.

4.3. “Customer Charge” shall mean a charge that does not depend on usage (dollar per customer, or $/customer).

4.4. “Kilowatt-hour” or “kWh” shall mean a unit of electricity usage.

~~4.4.~~4.5. “Minimum Charge” shall mean $20.00.~~the~~

~~4.5.~~4.6. “R.I. Gen. Laws” shall mean Rhode Island General Laws.

~~4.6.~~4.7. “R.I.P.U.C.” shall mean the Rhode Island Public Utilities Commission.

4.8. “Volumetric Charge” shall mean a charge that depends on usage (dollar per kilowatt-hour, or $/kWh).

5. TERMS AND CONDITIONS

Commented [A1]: Added for completeness

Commented [A2]: Added for ease of understanding relevance for readers

Commented [A3]: Edited to reflect Rhode Island terminology

Commented [A4]: Section added for clarity and consistency

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Commented [A5]: Note that this is a substantive edit reflecting the Company’s proposed revisions to the Low-Income Discount Rate. Please refer to the testimonies and schedules of Company Witness Kristin DeSousa and Company Witness Peter Blazunas.

RIPUC No. 2283
Sheet 2
Canceling R.I.P.U.C. No. 2225

THE NARRAGANSETT ELECTRIC COMPANY
LOW INCOME RATE (A-60)
ELECTRIC RETAIL DELIVERY SERVICE

5.1. The Company's Terms and Conditions then in effect~~in effect from time to time~~, where not inconsistent with any specific provisions hereof, are a part of this rate.

5.2. It is the responsibility of the customer to annually certify, by forms provided by the Company, the continued compliance with the foregoing provisions.

5.3. The Company may under unusual circumstances permit more than one set of living quarters to be served through one meter under this rate, but if so, the kilowatt-hours~~-~~ eligible for the credit described below shall be multiplied by the number of separate living quarters so served.

6. OTHER COMPANY TARIFF PROVISIONS

6.1. Any Customer served under this rate who is eligible for Last Resort Service shall receive such service pursuant to the Last Resort Service tariff.

7. CHARGE(S)

7.1. The charge consists of a Customer Charge (dollar per customer per month) and a Volumetric Charge (dollar per kilowatt-hour). The components of the Customer Charge and the Volumetric Charge are summarized in RIPUC No. 2095, and in RIPUC 2096 for customers utilizing Last Resort Service for their electricity supply.

7.2. The Monthly Charge will be the sum of the applicable Retail Delivery Service Charges set forth in RIPUC No. 2095, Summary of Retail Delivery Rates, subject to Section 9 below.

8. RATE ADJUSTMENT PROVISIONS

8.1. The charges for delivery service under this rate shall be subject to adjustment pursuant to the following provisions:

8.1.1. Customer Credit Provision

8.1.2. Energy Efficiency Programs Provision

8.1.3. Infrastructure, Safety, and Reliability Provision

8.1.4. Last Resort Service Adjustment Provision

8.1.5. LIHEAP Enhancement Plan Provision

8.1.6. Long Term Contracting for Renewable Energy Recovery Provision

8.1.7. Long Term Contracting for Renewable Energy Recovery Reconciliation Provision

8.1.8. Net Metering Provision

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Commented [A7]: Added to aid understanding and provide context for the Minimum Charge

Commented [A8]: Added to aid understanding

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THE NARRAGANSETT ELECTRIC COMPANY
LOW INCOME RATE (A-60)
ELECTRIC RETAIL DELIVERY SERVICE

8.1.9. Pension Adjustment Mechanism Provision

~~8.1.10. Performance Incentive Recovery Provision~~

~~8.1.11.~~8.1.10. Qualifying Facilities Power Purchase Rate

~~8.1.12.~~8.1.11. Renewable Energy Growth Program Cost Recovery Provision

~~8.1.13.~~8.1.12. Revenue Decoupling Mechanism Provision

~~8.1.14.~~8.1.13. Residential Assistance Provision

~~8.1.15.~~8.1.14. Storm Fund Replenishment Provision

~~8.1.16.~~8.1.15. Non-Bypassable Transition ~~Cost~~ Charge Adjustment Provision

~~8.1.17.~~8.1.16. Transmission Service Cost Adjustment Provision

9. LOW INCOME DISCOUNT

9.1. The Customer's total bill for service as determined based upon the provisions above, in addition to charges for generation service billed under the Complete Billing Service option pursuant to §2.1.1 of the Company's Terms and Conditions for Nonregulated Power Producers then in effect ~~from time to time~~, will be discounted by:

9.1.1. ~~Twenty-five percent (25%) for eligible customers enrolled in LIHEAP, SNAP, or SSI~~Seventy-five percent (75%) for eligible customers based on income qualification of fifty percent (50%) Federal Poverty Limit or less; or

9.1.2. ~~Seventy-five~~Sixty-six percent (~~75~~66%) for eligible customers based on income qualification of more than fifty percent (50%) Federal Poverty Limit up to seventy-five percent (75%) Federal Poverty Limit ~~or less~~; or ~~Thirty percent (30%) for eligible customers enrolled in Medicaid, General Public Assistance, or the Rhode Island Works or successor programs~~.

9.1.3. Fifty-six percent (56%) for eligible customers based on income qualification of more than seventy-five percent (75%) Federal Poverty Limit up to one hundred percent (100%) Federal Poverty Limit; or

9.1.4. Thirty-eight percent (38%) for eligible customers based on income qualification of more than one hundred percent (100%) Federal Poverty Limit up to one hundred fifty percent (150%) Federal Poverty Limit; or

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Commented [A11]: Revised to reflect correct tariff title.

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THE NARRAGANSETT ELECTRIC COMPANY
LOW INCOME RATE (A-60)
ELECTRIC RETAIL DELIVERY SERVICE

9.1.5. Ten percent (10%) for eligible customers based on income qualification of more than one hundred fifty percent (150%) Federal Poverty Limit up to two hundred fifty percent (250%) Federal Poverty Limit.

9.2. ~~In any case~~As illustrated through the examples below, a bill will not be discounted below the Minimum Charge.

9.2.1. For example, if a bill subtotal is $35.50 and sixty-six percent (66%) discount is applied, the discounted subtotal is $12.07, which is less than the Minimum Charge. Therefore, the customer will be billed the Minimum Charge of $20.00.

9.2.2. If the pre-discounted bill is less than or equal to the Minimum Charge, the Customer will be bill the pre-discounted bill. For example, if a bill totals $19.80 before application of a discount, the Customer will be charged $19.80.

~~9.1.2.~~9.3. Income qualification will be based on household income, household size, and Federal Poverty Limit guidelines from the U.S. Department of Health and Human Services, subject to routine updates, as performed by the Rhode Island Department of Human Services or its contracted Community Action Agencies (sometimes referred to as "Community Action Programs" or "CAP Agencies").

10. GROSS EARNINGS TAX

10.1. A Rhode Island Gross Earnings Tax adjustment will be applied to the charges determined above in accordance with Rhode Island General Laws.

11. NOTICE

11.1. Modifications to this rate shall be made in accordance with a notice filed with the Commission pursuant to R.I. Gen. Laws § 39-3-11(a) setting forth the amount of the revised factor and the amount of the increase or decrease. The notice shall further specify the effective date of such charges.

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Commented [A14]: This subsection explains how the minimum monthly payment works.

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Record Request No. 61

Request:

Referring to Operation Help, does that program produce any tax benefits for the Company and if so, where does that information appear in the schedules?

Response:

Operation HELP does not produce any tax benefits for the Company.

Prepared by or under the supervision of: Andrew Elmore

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.

Adam M. Ramos June 25, 2026 **Date**

Docket No. 25-45-GE The Narragansett Electric d/b/a Rhode Island Energy – Application for Approval of a Change in Electric and Gas Base Distribution Rates
Service List 6/1/2026

Parties' Name/Address	E-mail	Phone
The Narragansett Electric Company d/b/a Rhode Island Energy Jennifer Brooks Hutchinson, Esq. Jeremy Licht, Esq. Andrew S. Marcaccio, Esq. 280 Melrose Street Providence, RI 02907	JHutchinson@pplweb.com;	401-316-7429 401-784-4350 401-784-4263 401-578-2700
	JLicht1@pplweb.com;	
	AMarcaccio@pplweb.com;	
	JScanlon@pplweb.com;	
	SBriggs@RIEnergy.com;	
	CAGill@RIEnergy.com;	
	RLGresham@RIEnergy.com;	
	EMcCord@RIEnergy.com;	
	BESchuster@RIEnergy.com;	
	ASturgeon@pplweb.com;	
	KLDeSousa@RIEnergy.com;	
Hinckley, Allen, & Snyder, LLP Adam Ramos, Esq. Christine Dieter, Esq. 100 Westminster Street, Suite 1500 Providence, RI 02903-2319	aramos@hinckleyallen.com;	
	cdieter@hinckleyallen.com;	
	ssuh@hinckleyallen.com;	
	agiron@hinckleyallen.com;	
	ehanson@hinckleyallen.com;	
	babril@hinckleyallen.com;	
	cbreslin@hinckleyallen.com;	
Division of Public Utilities Margaret L. Hogan, Esq.	Margaret.L.Hogan@dpuc.ri.gov;	
	John.bell@dpuc.ri.gov;	
	Joel.munoz@dpuc.ri.gov;	
	al.mancini@dpuc.ri.gov;	

	Christy.Hetherington@dpuc.ri.gov;	
	Ellen.golde@dpuc.ri.gov;	
	Nicole.M.Corbin@dpuc.ri.gov;	
	John.R.Harrington@dpuc.ri.gov;	
	Kyle.J.Lynch@dpuc.ri.gov;	
	Gregory.Schultz@dpuc.ri.gov;	
	Mark.A.Simpkins@dpuc.ri.gov;	
	Leo.Wold@dpuc.ri.gov;	
	terry.mercer@dpuc.ri.gov;	
	wfwatson924@gmail.com;	
	aaron@rothschildfinancial.com;	
	roxiemccullar@consultant.com;	
Gregory L. Booth, PLLC 14460 Falls of Neuse Rd. Suite 149-110 Raleigh, NC 27614	gboothpe@gmail.com;	
Linda Kushner L. Kushner Consulting, LLC 514 Daniels St. #254	lkushner33@gmail.com;	
	roger@fsconline.com;	
	ebandera@gmail.com;	
Karl Pavlovic	kpavlovic@pcmgregcon.com;	
Dante Mugrace	dmugrace@pcmgregcon.com;	
Jake Van Reen Ashley Pou Deborah Schmelzer Michael Ballaban Dorothy Dickmann Dave Effron	jvanreen@vanreenaccounting.com; apou@vanreenaccounting.com; dschmelzer@vanreenaccounting.com; mballaban@vanreenaccounting.com; ddickmann@vanreenaccounting.com; DJEFFRON@aol.com;	
File an original & 9 copies w/: Stephanie De La Rosa, Commission Clerk **Public Utilities Commission** 89 Jefferson Blvd. Warwick, RI 02888	stephanie.delarosa@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Ryan.coyne@puc.ri.gov; Todd.bianco@puc.ri.gov; Alan.nault@puc.ri.gov; rhianon.small@puc.ri.gov; Kristen.L.Masse@puc.ri.gov;	401-780-2107
Intervenors		
Conservation Law Foundation Jamie Rhodes, Esq. James Crowley, Esq.	jrhodes@clf.org; jcrowley@clf.org;	

Rhode Island Office of Energy Resources William Owen Shauna Beland Nathan Cleveland Steven Chybowski David Augustyn	William.Owen@energy.ri.gov; Shauna.Beland@energy.ri.gov; Nathan.Cleveland@energy.ri.gov; Steven.Chybowski@energy.ri.gov; David.Augustyn@energy.ri.gov;	
Office of Attorney General Nick Vaz, Esq. 150 South Main St. Providence, RI 02903	nvaz@riag.ri.gov; mgomes@riag.ri.gov;	401-274-4400 x 2297
Green Energy Consumer Alliance Becca Miller, Tina Munter Evan Tao	becca@greenenergyconsumers.org; tina@greenenergyconsumers.org; etao@greenenergyconsumers.org;	
National Grid LNG, LLC Adler Pollock & Sheehan, P.C Alan M. Shoer, Esq. Todd D. Amaral, Esq. Tracey Toro David Lodemore, Esq. Senior Counsel National Grid USA	ashoer@apslaw.com; tamaral@apslaw.com; ttoro@apslaw.com; david.lodemore@nationalgrid.com;	(401) 274-7200 (781) 907-3704
Walmart, Inc. Higgins, Cavanagh & Cooney, LLP Melissa M. Horne, Esq. Arabella Adams	mhorne@hcc-law.com; aadams@hcc-law.com;	(401) 272-3500
The George Wiley Center Jennifer L. Wood, Esq. Troy H. Lange, Esq.	jwood@centerforjustice.org; tlange@centerforjustice.org;	
Amtrak McElroy, Deutsch, Mulvaney & Carpenter & McNees Wallace & Nurick, LLC Paul E. Dwyer, Esq Susan E. Bruce Kenneth R. Stark	pdwyer@mdmc-law.com; sbruce@mcneeslaw.com; kstark@mcneeslaw.com;	
Interested Persons		
Environmental Defense Fund Sonya Jindal Jolette Westbook	sjindal@edf.org; jwestbrook@edf.org;	
Industrial Economics Inc. Mark Ewen Maksim Malukoff	mewen@indecon.com; mmalukoff@indecon.com;	
Acadia Center Ben Butterworth Noah Berman Emily Koo	BButterworth@acadiacenter.org; nberman@acadiacenter.org; ekoo@acadiacenter.org;	
Celia B. O'Brien, Esq.	cbobrien@proton.me;	