Robinson+Cole

STEVEN J. BOYAJIAN

One Financial Plaza, 14th Floor
Providence, RI 02903-2485
Main (401) 709-3300
Fax (401) 709-3399
sboyajian@rc.com
Direct (401) 709-3359

Also admitted in Massachusetts

October 10, 2024

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 24-29-NG – 2024 Distribution Adjustment Clause and Gas Cost Recovery <u>Filing - Pre-Filed Rebuttal Testimony of James M. Stephens</u>

Dear Ms. De La Rosa:

On behalf of Rhode Island Energy,[1] I have enclosed the Pre-Filed Rebuttal Testimony of James M. Stephens in the referenced docket.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-709-3359.

Very truly yours,

Steven J. Boyajian

Enclosures

cc: Docket 24-29-NG Service List

[1] The Narragansett Electric Company d/b/a Rhode Island Energy.

<u>Certificate of Service</u>

I hereby certify that a copy of the cover letter and any materials accompanying this certificate were 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.

Heidi J. Seddon — October 10, 2024
Date

Docket No. 24-29-NG – Narragansett Electric Co. d/b/a Rhode Island Energy
2024 Gas Cost Recovery Filing (GCR) and 2024 Distribution Adjustment Clause (DAC)
Service List as of 7/31/2024

Name/Address	**E-mail**	**Phone**
The Narragansett Electric Company d/b/d Rhode Island Energy Celia B. O'Brien, Esq. 280 Melrose Street Providence, RI 02907	COBrien@pplweb.com; JHutchinson@pplweb.com; JScanlon@pplweb.com;	401-578-2700
Steven Boyajian, Esq. **Robinson & Cole LLP** One Financial Plaza, 14th Floor Providence, RI 02903	SBoyajian@rc.com; LPimentel@rc.com; HSeddon@rc.com;	401-709-3337
Rhode Island Energy Stephanie A. Briggs Jeffrey D. Oliveira Tyler G. Shields Peter R. Blazunas James M. Stephens Stuart Wilson Tim Jones Michele V. Leone Laeyeng H. Hunt Brandon W. Flynn Kim Dao	SBriggs@pplweb.com; JOliveira@pplweb.com; TGShields@pplweb.com; PBlazunas@ceadvisors.com; JMStephens@pplweb.com; Stuart.Wilson@lge-ku.com; tim.jones@lge-ku.com; MVLeone@RIEnergy.com; LHHunt@RIEnergy.com; BFlynn@RIEnergy.com; KDao@RIEnergy.com;	
Division of Public Utilities and Carriers (DIV)	Leo.wold@dpuc.ri.gov; John.bell@dpuc.ri.gov;	401-780-2177

Leo Wold, Esq. Division of Public Utilities and Carriers 150 South Main St. Providence, RI 02903	Al.mancini@dpuc.ri.gov; Margaret.L.Hogan@dpuc.ri.gov; Paul.roberti@dpuc.ri.gov; Ellen.Golde@dpuc.ri.gov; Machaela.Seaton@dpuc.ri.gov;	
Jerome Mierzwa **Exeter Associates, Inc.** 10480 Little Patuxent Parkway, Suite 300 Columbia, MD 21044	jmierzwa@exeterassociates.com; lmorgan@exeterassociates.com;	410-992-7500
David Effron **Berkshire Consulting** 12 Pond Path North Hampton, NH 03862-2243	Djeffron@aol.com;	603-964-6526
File an original & 9 copies w/ PUC: Stephanie De La Rosa, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	stephanie.delarosa@puc.ri.gov; Patricia.lucarelli@puc.ri.gov; Alan.nault@puc.ri.gov; Christopher.Caramello@puc.ri.gov; Todd.bianco@puc.ri.gov;	401-780-2107
Christopher Kearns **Office of Energy Resources**	Christopher.Kearns@energy.ri.gov; William.Owen@energy.ri.gov;	
Nicholas Vaz, Esq. **RI Attorney General Office**	nvaz@riag.ri.gov; mbedell@riag.ri.gov;	
James Crowley, Esq. **Conservation Law Foundation**	jcrowley@clf.org;	

PRE-FILED REBUTTAL TESTIMONY

OF

JAMES M. STEPHENS

OCTOBER 10, 2024

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. My name is James M. Stephens. My business address is 1595 Mendon Road, Cumberland, Rhode Island 02864.

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

A. I am the Director of Gas Procurement and Gas Control for The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company").

Q. Have you previously submitted pre-filed testimony in this proceeding?

A. Yes. On August 30, 2024, I submitted pre-filed direct testimony concerning the Company's gas supply plan for the twelve-month period beginning November 1, 2024, and concerning the Company's Natural Gas Portfolio Management Plan.

II. Purpose and Structure of Rebuttal Testimony

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the observations and recommendation provided in the direct testimony of Jerome D. Mierzwa on behalf of the Division of Public Utilities and Carriers ("Division") regarding the level of design peak hour costs proposed by the Company to be removed from the Gas Cost Recovery ("GCR") and recovered through the Distribution Adjustment Clause ("DAC").

Q. How is your rebuttal testimony structured?

A. Section I provides an introduction. Section II explains the purpose and structure of my rebuttal testimony. Section III provides my response to Mr. Mierzwa's observations and recommendation regarding the Company's reallocation of certain design peak hour costs from the GCR to the DAC. Section IV is the conclusion.

III. <u>Design Peak Hour Costs</u>

Q. Please summarize Mr. Mierzwa's observations and recommendation regarding the Company's reallocation of certain design peak hour costs from the GCR to the DAC.

A. As discussed on pages 8 through 10 of his pre-filed direct testimony dated October 3. 2024, Mr. Mierzwa observed a decrease in the non-LNG assets required to meet design peak hour demands and an overall decrease in the design peak hour costs removed from the GCR to be recovered through the System Pressure Factor component of the DAC in this year's proceeding (i.e., the 2024/25 GCR period) relative to last year's proceeding (i.e., the 2023/24 GCR period). As explained by Mr. Mierzwa, the total daily contract quantity of non-LNG assets required to meet design peak hour demands are 14,100 Dth per day lower in the 2024/25 GCR as compared to the 2023/24 GCR period, and the total fixed costs of assets removed from the GCR for recovery through the System Pressure Factor of the DAC decreased from $25.84 million in 2023/24 to $15.87 million in 2024/25. Based on his observations, Mr. Mierzwa recommended the Company provide in rebuttal testimony, full and adequate justification for the decrease in the design peak hour demand gas costs to be removed from the GCR and recovered through the DAC.[1]

Q. Please explain the reduction in total daily contract quantity of non-LNG assets required to meet design peak hour demands that was described by Mr. Mierzwa.

A. The 14,100 Dth per day reduction in total daily contract quantity of non-LNG assets required to meet design peak hour demand results from the March 31, 2024 expiration of a contract with Constellation LNG LLC ("CLNG") for 14,100 Dth per day delivered to the Company's citygates on the pipeline operated by Algonquin Gas Transmission, LLC ("AGT"). This resulted in a decline in the Company's total daily contract quantity of non-LNG assets required to meet design peak hour demands from 54,100 Dth per day in 2023/24 to 40,000 Dth per day in 2024/25.[2]

Q. Please describe the CLNG contract that expired on March 31, 2024.

A. The CLNG contract was a multi-year contract that provided the Company with 14,100 Dth per day of citygate delivered gas supply. As a citygate delivered service, the CLNG contract bundled CLNG gas supply with CLNG contracted capacity on AGT. The total allowed contract quantity was 507,600 Dth per year, with a maximum daily quantity of

[1] See, Direct Testimony of Jerome D. Mierzwa, p. 8.
[2] See, also, the Company's response to data request Division 4-9 in this docket.

14,100 Dth per day, and the term of the CLNG contract was from December 1, 2019, through March 31, 2024.

Q. Did the Company have concerns regarding the long-term availability of supplies from CLNG prior to the expiration of the CLNG contract?

A. Yes, in its annual gas long-range resource and requirements plan ("LRP") filings since 2021, the Company has outlined its concerns regarding the availability and viability of CLNG with respect to the Company's gas supply portfolio and strategy. For example, starting in the 2021 LRP, the Company stated that: "At this time, it remains unclear if Constellation LNG LLC will continue to operate its LNG import terminal at Everett, MA beyond 2024."[3]

Q. Did the Company undertake a contracting strategy to replace the CLNG bundled service contract in light of its concerns about the continued availability of supply under the CLNG contract?

A. Yes, subsequent to the 2021 LRP, the Company implemented a phased strategy of replacing the pipeline capacity and gas supply components of the CLNG contract. The Company endeavored to replace the CLNG supply and capacity resources prior to the expiration of the CLNG contract to ensure that appropriate replacement resources were

[3] 2021 LRP, p. 28.

available to meet customer demand by the beginning of the winter following the expiration of the CLNG contract (i.e., by 2024/25).

Q. How did the Company replace the pipeline capacity component of the CLNG contract?

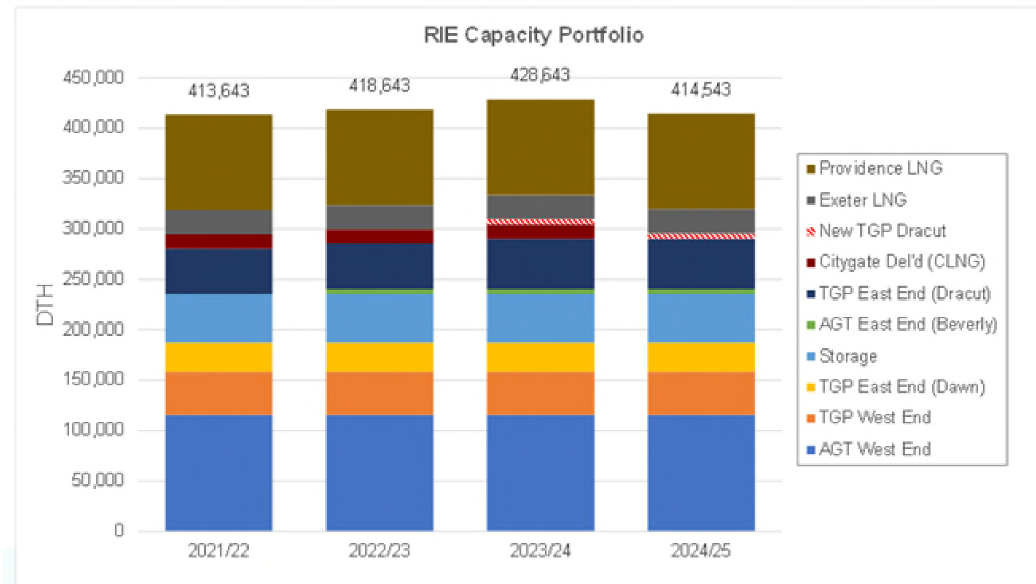
A. The Company undertook the following actions to replace the capacity component of the CLNG contract:

- The Company entered into a new contract for incremental pipeline capacity on AGT for 5,000 Dth per day from Beverly, Massachusetts to the Company's citygate beginning in 2022/23.[4]
- The Company increased its capacity on Tennessee Gas Pipeline, L.L.C. ("TGP") by 10,000 Dth per day from Dracut, Massachusetts to the Company's citygates beginning in 2023/24 by way of: (i) a 5,000 Dth per day step-up in capacity on an existing TGP contract, and (ii) a new 5,000 Dth per day capacity contract with TGP.[5]

Consequently, starting in 2024/25, with the expiration of the CLNG contract, the Company had effectively replaced the 14,100 Dth per day of CLNG capacity with 15,000

[4] See, 2022 LRP, p. 22 and 28.
[5] See, 2023 LRP, p. 26.

Dth per day of capacity contracted by the Company. The stacked bar chart below illustrates the changes in the Company's capacity portfolio.



As illustrated by the chart above, the Company's 2024/25 capacity portfolio is essentially equivalent to the Company's 2021/22 capacity portfolio reflecting the expiration of the CLNG contract and the Company's executed pipeline capacity replacement strategy.

Q. How did the Company replace the gas supply component of the CLNG contract?

A. As discussed in the 2024 LRP filed in Docket No. 24-27-NG, the Company entered into a contract with Repsol Energy North America Corporation ("Repsol") for firm gas supply effective November 1, 2024, for a primary term of five years. The Repsol contract provides the Company the right, but not the obligation, to call on Repsol to deliver up to

15,000 Dth per day, and a total contract quantity of 525,000 Dth per year, of gas supply from Repsol's Saint John LNG terminal in Atlantic Canada to the interconnection with AGT at Beverly, Massachusetts and/or the interconnection with TGP at Dracut, Massachusetts.[6]

Q. Does the combination of pipeline capacity contracted by the Company together with the Repsol contract replace the volume of bundled citygate delivered service under the CLNG contract?

A. Yes, the Company's capacity contracts on AGT and TGP, as outlined above, together with the gas supply contract with Repsol, provide 15,000 Dth per day of gas supply deliverable to the Company's citygates and, therefore, replace the bundled service provided by the CLNG contract.

Q. What other factors contributed to the overall decrease in the design peak hour gas costs observed by Mr. Mierzwa?

A. There are several market factors that have contributed to the overall decrease in the Company's design peak hour gas costs in the current 2024/25 GCR period relative to prior years. Specifically, in February 2022 Russia's invasion of Ukraine resulted in various energy market implications, including the introduction of significant volatility in

[6] See, 2024 LRP, p. 25-26.

the global prices for LNG. Because the New England region imports LNG for winter supply, this volatility impacted liquidity and price offerings in New England resulting in much higher costs for certain winter supplies during the 2022/23 GCR period (i.e., approximately $68.66 million of costs allocated from the GCR to the DAC). Although prices decreased significantly for the 2023/24 GCR period, the lower liquidity continued to influence market participants and deal structures (e.g., fixed cost/must-take contracts). The allocation of fixed costs from the GCR to the DAC for the 2023/24 GCR period totaled approximately $25.84 million.[7] Through its Request for Proposals process for the procurement of winter supplies for the 2024/25 GCR period, the Company observed an increase in the number of market participants and a variety of deal structures resulting in a lower fixed cost for certain winter supplies (e.g., no fixed cost/must-take contracts).[8] These lower costs are reflected in the decreased fixed design peak hour costs allocated from the GCR to the DAC of approximately $15.87 million.

IV. <u>Conclusion</u>

Q. Does this conclude your rebuttal testimony?

A. Yes.

---

7 See, also, the Company's response to data request Division 5-7 in Docket No. 23-23-NG regarding the Company's 2023 Gas Cost Recovery filing, provided as Attachment JMS-1 (Rebuttal).

8 See, also, the Company's response to data request Division 1-31 in this docket.

Division 5-7

Request:

Please explain in detail why the system pressure factor/design hour costs to be reflected in the DAC for the period November 2023 – October 2024 are significantly lower than the system pressure factor/design hour costs reflected in the DAC for the period November 2022 – October 2023.

Response:

The system pressure factor/design hour costs to be reflected in the DAC for the period November 2023 through October 2024 are significantly lower than the system pressure factor/design hour costs reflected in the DAC for the period November 2022 through October 2023 primarily because of the cost of imported LNG supplies. Last year, when the Company issued its RFPs, world events, specifically the war in Ukraine greatly impacted the global LNG prices. The cost of LNG supplies is significantly lower this year. Please see the table below for the TTF Index for the period August 2022 through March 2023 compared to the period August 2023 through March 2024 (*October 2023 through March 2024 indices are as of September 5, 2023*).

8/1/2022	$50.69	**8/1/2023**	$9.66
9/1/2022	$69.36	**9/1/2023**	$11.10
10/1/2022	$59.81	**10/1/2023**	*$10.67*
11/1/2022	$39.91	**11/1/2023**	*$14.00*
12/1/2022	$35.38	**12/1/2023**	*$15.86*
1/1/2023	$36.98	**1/1/2024**	*$16.52*
2/1/2023	$20.42	**2/1/2024**	*$16.67*
3/1/2023	$16.71	**3/1/2024**	*$16.53*

Prepared by or under the supervision of: Megan Borst
(Pursuant to the Transition Services Agreement)