UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

JEFFREY M. PENTZ

New Hampshire Public Utilities Commission

Docket No. DE 24-065

June 7, 2024

TABLE OF CONTENTS

LIST OF SCHEDULES

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jeffrey M. Pentz. My business address is 6 Liberty Lane West, Hampton, NH 03842.

Q. What is your relationship with Unitil Energy Systems, Inc.?

A. I am employed by Unitil Service Corp. ("USC") as Supervisor of Energy Supply. USC provides management and administrative services to Unitil Energy Systems, Inc. ("UES", "Unitil" or the "Company") and Unitil Power Corp. ("UPC").

Q. Please briefly describe your educational and business experience.

A. I received my Bachelor of Arts degree in Economics from the University of Massachusetts. Before joining USC, I worked as a Contracting and Transaction Analyst with Mint Energy which is a retail electric supplier. My range of responsibilities included contract negotiation with brokers and customers, retail billing, and sales. Prior to Mint Energy, I worked as a data analyst for Energy Services Group. My responsibilities included supplier business transaction testing and integration with regulated utilities. I joined USC in February 2016 as an Energy Analyst with the Energy Contracts department. In January 2019 I was promoted to Senior Energy Analyst and in January 2024, promoted to Supervisor, Energy Supply I have primary responsibilities in the areas of load settlement, renewable energy credit procurement, renewable portfolio standard compliance, default service procurement, market research and operations, and monitoring renewable energy policy.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes, I have testified before the Commission in previous Default Service Solicitation proceedings.

II. PURPOSE OF TESTIMONY

Q. Please describe the purpose of your testimony.

A. This testimony documents the solicitation process followed by UES in its acquisition of default service power supplies for its G1 and Non-G1 customers as approved by the Commission in Order No. 25,397, dated July 31, 2012 (the "Order") granting UES's Petition for Approval of Revisions to its Default Service Solicitation Process for G1 and Non-G1 Customers. Subsequently, in Commission Order No. 26,973 issued on March 15, 2024, the Commission approved a modification to the solicitation process whereby the Company will include a self-supply market-based tranche of 10% for Non-G1 customers. With the current Request for Proposal ("RFP"), UES has contracted for a six-month default service power supply for 90% of its small customer group (Non-G1); 90% of its medium customer group (Non-G1); and 100% of its large customer group (G1) service requirements. The remaining 10% of power supply will be purchased directly in the ISO hourly markets. Service begins on August 1, 2024.

Q. Please describe the documents provided with this filing.

Supporting documentation and additional detail of the solicitation process is provided in the Bid Evaluation Report ("Report"), attached as Schedule JMP-1. The structure, timing and requirements associated with the solicitation are fully described in the RFP issued on May 7, 2024 and is attached as Schedule JMP-2. An updated Customer Migration Report is attached as Schedule JMP-3. The Customer Migration Report shows monthly retail sales and customer counts supplied by competitive generation, total retail sales and customer counts (the sum of default service and competitive generation) and the percentage of sales and customers supplied by competitive generation. The report provides a rolling 13-month history which covers the period from April 2023 through April 2024. Renewable Portfolio Standard ("RPS") Compliance Cost Estimates are included as Schedule JMP-4. My testimony reviews UES's approach to compliance with the RPS which went into effect in January 2008. Schedule JMP-4 details projected obligations and price assumptions for the coming rate period. The price assumptions are based on recent market data information and alternative compliance payment prices. Schedule JMP-5 provides historical price data by customer group that is no longer subject to confidential treatment. This schedule provides pricing histories associated with the most recent six-month rate periods for Non-G1 and G1 customers for which all pricing is currently subject to the Federal Energy Regulatory Commission's quarterly reporting requirements. Schedule JMP-6 details the pricing estimate for the 10% market tranche. Lastly, Schedule JMP-7 provides the final wholesale power supply price by calculating the weighted average price of both the estimated market tranche (10%) and fixed price tranche (90%).

Q. Please summarize the approvals UES is requesting from the Commission.

A. UES requests that the Commission:

- Find that: UES has followed the solicitation and self-supply process approved by the Commission; UES's analysis of the bids submitted was reasonable; and UES has supplied a reasonable rationale for its choice of the winning suppliers.
- Find that: the price estimates of renewable energy certificates ("RECs") proposed by UES, which are based on actual purchases or current market prices and information, are appropriate for inclusion in retail rates.
- On the basis of these findings, conclude that the power supply costs resulting from the solicitation are reasonable and that the amounts payable to the sellers under the supply agreements are approved for inclusion in retail rates.
- Issue an order granting the approvals requested herein on or before June 14, 2024, which is five (5) business days after the date of this filing.

III. SOLICITATION PROCESS

Q. Please discuss the Solicitation Process UES employed to secure the supply agreements for default service power supplies.

A. UES conducted an open solicitation in which it actively sought interest among potential suppliers to provide load-following power supply to its Default Service customers. UES provided bidders with appropriate information to enable them to assess the risks and obligations associated with providing supply services. UES did not discriminate in favor of or against any individual potential supplier who expressed interest in the solicitation. UES negotiated with all potential suppliers who submitted proposals to obtain the most favorable terms from each potential supplier. The structure, timing and requirements associated with the solicitation are fully described in the RFP issued on May 7, 2024. This is attached as Schedule JMP-2 and is summarized in the Bid Evaluation Report attached as Schedule JMP-1.

Q. Were there any changes made to the Solicitation Process?

A. Yes. On January 22, 2024 the Company made a proposal pursuant to the requirements of Order No. 26,910, whereby the Commission ordered UES to submit a proposal to self-supply a portion of Default Service through direct market purchases from ISO-NE. The proposal changes the existing procurement process by including a 10% ISO-NE market-based tranche for UES's Non-G1 default service customer groups, while continuing with a reduced 90% tranche of fixed price load following power supply to be solicited from wholesale suppliers. UES's proposal was approved by the commission on March 15, 2024 in Order no. 26,973.

Q. How did UES ensure that the RFP was circulated to a large audience?

A. UES announced the electronic availability of the RFP to a list of power suppliers and brokers. The RFP was also distributed to all members of the NEPOOL Markets Committee. As a result, the RFP had wide distribution throughout the New England supply marketplace, including distribution companies, consultants, and members of public agencies. UES followed up the E-mail solicitation with outreach to power suppliers to solicit their interest in bidding on any and all customer classes.

Q. What information was provided in the RFP to potential suppliers?

A. The RFP provides background information and historical data, details the service requirements and commercial terms, explains the process for selecting the winning bidders. To gain the greatest level of market interest in supplying the load, UES provided potential bidders with appropriate and accessible information. Data provided included historical hourly default service loads and daily capacity tags for each customer group; class average load shapes; historical monthly retail sales and customer counts by rate class and supply type; and the evaluation loads, which are the estimated monthly volumes that UES would use to weigh bids in terms of price. The retail sales report and the historical loads and capacity tag values were updated prior to final bidding to provide the latest information available. Additionally, a supplemental data file including load volumes sorted by rate class and supply type were provided for each individual town in the UES service territory.

Q. How did UES evaluate the bids received?

A. UES evaluated the bids on both quantitative and qualitative criteria, including price, market conditions, creditworthiness, willingness to extend adequate credit to UES to facilitate the transaction, capability of performing the terms of the RFP in a reliable manner and the willingness to enter into contractual terms acceptable to UES. UES compared the pricing strips proposed by the bidders by calculating weighted average prices for the supply requirement using the evaluation loads that were issued with the RFP.

Q. How did market conditions impact the prices for this next period?

A. Overall, the winning supplier wholesale pricing submitted for the Small and Medium classes (Non-G1) for the upcoming six-month period of August 1, 2024 through January 31, 2025 is 3.4% higher than the current period of February 1, 2024 to July 31, 2024. Recent stability in the ISO-NE electricity forward pricing markets as well as Henry Hub natural gas markets has resulted in a fairly stable comparison of bid results when comparing to the prior period. Considering current market conditions, the Company determined that the pricing submitted was market based and competitive.

Q. What impact, if any, did active or pending community aggregations have on the solicitation results?

A. There are numerous cities and towns within UES' service territory which are either active, or in the planning stages of forming aggregation supply. As a result, there is significant default service load attrition expected for the upcoming service period of August 1, 2024 through January 31, 2025. The migration adds an additional variable into an area where suppliers already feel market related risks. Upon review and analysis of the winning bid prices compared to energy futures from current and prior solicitations, the Company didn't see any notable increases in bidder risk premiums caused my municipal aggregations.

Q. Please summarize the winning bidders for each customer supply requirement.

A. UES selected Constellation Energy Generation ("Constellation") as the winning bidder for the small customer (Non-G1) supply requirement (90% share) and the medium customer (Non-G1) supply requirement (90% share). UES selected Nextera Energy Marketing, LLC ("Nextera") as the winning bidder of the large customer (G1) supply requirement (100% share). All three transactions are for a period of six months. UES believes that Nextera and Constellation offer the best overall value in terms of both price and non-price considerations for the supply requirements sought.

Q. Please describe the contents of the Bid Evaluation Report.

A. Schedule JMP-1 contains the Bid Evaluation Report which further details the solicitation process, the evaluation of bids, and the selection of the winning bidders. The Report contains a narrative discussion of the solicitation process. Additional discussion regarding the selection of the winning bidders is provided along with several supporting exhibits that list the suppliers who participated, as well as the pricing they submitted and other information considered by UES in evaluating final proposals, including redlined versions of the final supply agreements.

On the basis of the information and analysis contained in the Bid Evaluation Report, UES submits that it has complied with the procurement process approved by the Commission, and that the resulting default service power supply costs are reasonable and that the amounts payable to the sellers under the supply agreements should be approved for inclusion in retail rates.

Q. Please elaborate on the supplier response to this solicitation.

A. UES reached out to a number of suppliers early in the process to solicit and gauge supplier interest. Bidder response for this solicitation was similar when compared to the prior solicitation, with one less bidder for the Small Customer Group, and one additional bidder for the Large Customer Group. A couple suppliers that have participated in the past elected not to do so this time stating concerns primarily about municipal aggregation migration risk.

Q. Please indicate the planned issuance date, filing date and expected approval date associated with UES's next default service solicitation.

A. Similar to the current solicitation, UES's next default service solicitation will be for ninety percent (90%) of the small, medium and large customer supply requirements for a six-month period. Delivery of supplies will begin on February 1, 2025. UES will be issuing the next solicitation on November 5, 2024 with final bids being due December 3, 2024.

IV. RENEWABLE PORTFOLIO STANDARD COMPLIANCE

Q. Please explain how UES is complying with the Renewable Portfolio Standard requirements.

A. In accordance with the settlement agreement dated July 16, 2009 in Docket No. DE 09-009, and as amended on December 6, 2011, UES will conduct two REC RFPs during each compliance year to obtain Existing RECs and/or Forward RECs to meet 100% of its projected REC obligations. In addition, UES may make REC purchases outside of the RFP process when it finds it advantageous to do so. To meet its 2024 RPS compliance requirements, UES will issue an RFP in the fall of 2024 for its remaining 2024 RPS requirements and possibly half of its 2025 RPS requirements. Tab A includes an exhibit summarizing UES's REC purchases for RPS compliance.

Q. Please describe UES's estimates of RPS compliance costs.

A. The current solicitation is for default service power supplies to be delivered beginning August 1, 2024. Schedule JMP-4 lists the percentage of sales and the resulting REC requirement for each class of RECs for RPS compliance along with UES's cost estimates for the period beginning August 1, 2024. UES's cost estimates are based on current market prices as communicated by brokers of renewable products, recent purchases of RECs, and alternative compliance payment rates ("ACP").

Q. Does UES's estimate of RPS costs incorporate the latest RPS requirements for 2024 and 2025?

A. Yes. The following table provides a summary of the RPS requirements.

NH Renewable Portfolio Standards: 2024 and 2025

Calendar Year	Class I *	Class I Thermal	Class II	Class III	Class IV
2024	14.10%	2.2%	0.7%	8.00%	1.5%
2025	15.00%	2.2%	0.7%	8.00%	1.5%

*Class I is the gross requirement which includes Class I Thermal. The net Class I requirement less the Class I Thermal Carve-Out requirement is 11.9% for 2024

Schedule JMP-4 RPS Compliance Costs Estimates incorporates the latest RPS requirements shown here.

Q. Is there anything you would like to add?

A. Yes. At this time UES has 5,632 Vintage 2021 Class III RECs at a value of $190,362 that it was unable to use to meet the 2022 or 2023 RPS Class III REC obligations. This is due to the reduction in compliance obligations made by the Department of Energy, the 30% limit in using "banked" RECs in a single compliance year as specified in RSA 362-F:7 and the limit on using, banked RECs only in the two subsequent years from the REC vintage year.

Q. What were the NH Class III Compliance Obligations from 2021-2023?

A. The NH Class III obligation was initially set at 8% of retail sales for the compliance years 2021-2023. These obligations were then reduced by the Department of Energy to 1.0%, 0.5%, and 0.5% respectively from 2021-2023. The reductions to the compliance requirements for 2021 occurred on March 31, 2022. The reductions to the requirements for 2022 and 2023 occurred on April 11, 2023 and March, 5, 2024

Q. Please explain the timing and pricing factors surrounding UES' purchase of the NH Class III RECs in 2021?

A. UES purchased, based on estimated retail sales, 14,500 RECs, or 25% of the total requirement for NH Class III on October 26, 2021. In other words, UES did not purchase the full 8% of retail sales requirement, but only purchased 2%. Additionally, the purchase price of the RECs was $33.80, which was below the 2021 Alternative Compliance Payment of $34.99. The purchase was made months before the RECS compliance obligation was reduced by the Department of Energy to 1.0% on March 31, 2022.

Q. Was the purchase of these 2021 NH Class III RECs a prudent decision?

A. Yes, the Company believes its decision was prudent. Most notably, the Company relies on set compliance requirement obligations to make purchases throughout the compliance year. Additionally, UES did not purchase the full 8% requirement, but only 25% of the 8% (or 2% of the total), which was the compliance requirement for the majority of the compliance year. Based upon the information known and available at the time, the Company believes its decision to purchase NH Class III RECs at this level, which was below the 8% requirement, was prudent.

Q. **Has the cost of the 5,632 Vintage 2021 Class III RECs been recovered by the Company through its Default Service rates?**

A. Yes. Please refer to the Testimony of Linda S. McNamara that explains the accounting treatment/cost recovery of these RECs.

VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

DE 24-065 – Unitil Energy Systems, Inc.

Default Service RFP
Bid Evaluation Report

Small Customers (100%): August 1, 2024 – January 31, 2025
Medium Customers (100%): August 1, 2024 – January 31, 2025
Large Customers (100%): August 1, 2024 – January 31, 2025

RFP Issue Date: *May 7, 2024*

Filing Date: June 7, 2024

Unitil Energy Systems, Inc. (“UES”)
Default Service RFP
Bid Evaluation Report

Table of Contents

Unitil Energy Systems, Inc.
Bid Evaluation Report

Introduction

On Tuesday, May 7, 2024, UES announced that its Request for Proposals ("RFP") for Default Service ("DS") supplies for the period beginning August 1, 2024 was available. In accordance with UES's DS supply proposal as approved by the Commission in Order No. 26,973 ("the Order"), UES issued this RFP to obtain fixed monthly price offers to supply ninety (90%) of the small and medium customer groups, and 100% large customer groups for the six-month period beginning August 1, 2024 and ending on January 31, 2025.

The RFP issued on May 7, 2024, was consistent in form and substance to the prior RFP issued by UES on October 31, 2023. A copy of the RFP documents issued to the market on May 7, 2024, including the Proposal Submission Form, the proposed Power Supply Agreement ("PSA"), the proposed PSA Amendment, and Non-Disclosure Agreement are attached to the petition as Schedule JMP-2.

UES received bids from qualified suppliers who competed to serve the load requirements. The winner of the small customer (Non-G1) default service requirement and the medium customer (Non-G1) default service requirement was Constellation Energy Generation ("Constellation"). The winner of the large customer (G1) default service requirement was Nextera Energy Marketing, LLC ("Nextera"). These suppliers offered the best overall value for the service requirements sought. The default service power supply prices obtained by UES are the result of a competitive solicitation and are reflective of current market conditions. This Bid Evaluation Report ("Report") describes UES's solicitation process and its selection of the winning bidders.

UES's comparison of bids, which is confidential and for which UES seeks protective treatment as described in the cover letter and motion for protective treatment accompanying this filing, is included in Tab A to this Report. Details of the market response, including bid prices, and certain non-price considerations and selection rationale, are also included in the Tab A materials.

Solicitation Process

UES issued its request for proposals on Tuesday, May 7, 2024 to 12 suppliers and brokers. The RFP was also distributed to all members of the NEPOOL Markets Committee. As a result, the RFP had wide distribution throughout the New England supply marketplace.

The RFP documents and accompanying data files were provided to interested parties via the Company's RFP website. The RFP described the specifics of UES's DS, the related customer-switching rules, the form of power service sought, and the evaluation criteria. The RFP documents included a Proposal Submission Form, a proposed Power Supply Agreement ("PSA"), proposed PSA Amendment for use by suppliers who are currently serving load or have previously served load, a Non-Disclosure Agreement, and various data files.

To gain the greatest level of market interest in supplying the loads, UES provided potential bidders with appropriate information, including historical hourly loads and daily capacity tag values for UES's DS customers for the period from January 1, 2019 through April 30, 2024. UES also provided an Excel spreadsheet containing historic retail monthly sales and customers reports from January 1, 2019 through April 30, 2024. The monthly reports detail by customer rate class the monthly retail billed kWh sales and the number of customers receiving default service and competitive generation supply. UES also provided class average load shape (8760 hours) data and distribution loss factors associated with each rate class. Lastly, UES provided Bid Sheets with estimated monthly volumes expected to be purchased under default service for the term during which service was sought. As described in the RFP, UES used these estimated monthly loads to evaluate and weigh competing bids in terms of price. In the RFP, UES refers to these estimated loads as the "evaluation loads." The RFP makes clear that the supplier's obligation is for actual loads and is not in any way limited by the RFP's use of the evaluation loads.

Throughout the solicitation, UES contacted potential bidders, responded to bidder questions, researched bidder qualifications and actively participated in maintaining bidder interest through regular telephone and electronic communications. UES did not discriminate in favor of or against any individual potential supplier who expressed interest in the solicitation, but endeavored to assist each interested bidder in their understanding of the transaction sought via the solicitation.

On May 21, 2024, UES received indicative proposals from respondents that included detailed background information on the bidding entity, proposed changes to the contract terms and indicative pricing. UES reviewed the proposals and worked with the bidders to establish and evaluate their creditworthiness, their extension of adequate credit to UES to facilitate the transaction, their capability of performing the terms of the PSA in a reliable manner and their willingness to enter into contractual terms acceptable to UES. UES negotiated with all potential suppliers who submitted proposals to obtain the most favorable contract terms. All bidders were invited to submit final bids.

On June 4, 2024, UES received final pricing from bidders and conducted its evaluation. UES selected and notified Constellation that they were the winner of the small and medium default service requirements. UES selected Nextera as the winner of the large default service requirement. All other bidders were notified that they were not selected.

Selection of Winning Bidders

UES based its selection of the winning bidders on both quantitative and qualitative criteria. Indicative bids were compiled and ranked based upon weighted average prices using the evaluation loads that were issued to bidders and assessed for any outliers. UES coordinated with bidders to obtain the best non-price terms each bidder was willing to offer and to establish confidence in each bidder's ability to perform. Final bids were again ranked based on the weighted average prices using the evaluation loads. In addition to the bid price and ability to meet credit requirements, UES also performed a qualitative review of each bidder's ability to provide default service during the service period, including the following:

- The bidder's past experience in providing similar services to UES;
- The bidder's past experience in providing similar services to other companies in New England and other regions;
- The bidder's demonstrated understanding of the market rules related to the provision of Default Service;
- The bidder's demonstrated understanding of its obligations under the proposed Power Service Agreement;
- Whether there have been any past or are there any present events that are known that may adversely affect the bidder's ability to provide Default Service.

UES has significant prior direct experience and working relationships with all of the suppliers who participated in the RFP. For newer suppliers, UES seeks input from references in order to verify the capabilities of the supplier, as well as performing an internal review of the new suppliers' financials for creditworthiness. The comparison of bids, which is confidential and which includes materials documenting UES's rationale for its selection of the winning bidders, is contained in Tab A.

DE 24-065 – Unitil Energy Systems, Inc.

Default Service RFP
Bid Evaluation Report

Small Customers (90%): August 1, 2024 – January 31, 2025
Medium Customers (90%): August 1, 2024 – January 31, 2025
Large Customers (100%): August 1, 2024 – January 31, 2025

RFP Issue Date: May 7, 2024

REDACTED

TAB A
CONFIDENTIAL ATTACHMENT

Filing Date: June 7, 2024

Unitil Energy Systems, Inc. ("UES")
Default Service RFP
Bid Evaluation Report

Tab A. Comparison of Bids

Table of Contents

Unitil Energy Systems, Inc.
Bid Evaluation Report - Tab A

Discussion of Results

On June 4, 2024 UES selected Constellation Energy Generation, LLC. ("Constellation") as the winner of the small customer (Non-G1) supply requirement, and the medium customer (Non-G1) supply requirement. Nextera Energy Marketing, LLC (Nextera) was the winning bidder of the large customer (G1) supply requirement. The supply requirements are for the provision of default service power supplies beginning August 1, 2024. As shown in the attached pages, the winning bidders represent the results of an open, competitive solicitation process.

<u>Bidding Activity</u>

[redacted] The attached bidder key in Tab A(1) lists all the participating suppliers. UES reviewed the bids received, evaluated the pricing as competitive, and proceeded to contract with the winning suppliers.

<u>Selection of Winners</u>

The pricing comparison summaries shown in Tab A(2) list the bids received and ranks the bids according to price. The summaries also indicate the payment terms negotiated with each bidder and the interest costs associated with the payment terms calling for payment earlier than the end of the month after service is delivered. The total costs, and the deltas from the low price bidder's costs, listed in these sections include the interest costs associated accelerated payment terms.

Contract Provisions

To implement the transactions, UES executed Amendments to the existing Power Supply Agreements ("PSA") with Nextera and Constellation. A Redlined version of the Amendments are attached as Tab A(8). The Amendments for Nextera and Constellation adds the new transactions to Appendices A and B of their existing PSA. The Amendments are subject to termination if UES is unable to obtain Commission approval of the Petition by June 14, 2024. UES respectfully submits that a Commission decision by June 14, 2024, in accordance with the schedule established in Order No. 24,511, is important to the ongoing vitality of the solicitation process.

The materials listed in the Table of Contents as Tab A(1) through Tab A(9) follow. UES welcomes feedback from the Commission on the value of the following materials in facilitating its review of the solicitation results.

Tab A(1). Bidder Key

The first item attached to this Comparison of Bids identifies the bidding entities who responded to UES's RFP for default service supplies. The materials that follow generally refer to the respondents as Bidder A, Bidder B, and so on.

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
Indexed Bidder List with Selected Winners

Index	Bidding Entity
[redacted]	

Tab A(2). Pricing Summaries

The second item attached to this Comparison of Bids shows summaries of the final bids received, including the total costs calculated on the basis of the evaluation loads and a ranking of the bids in terms of evaluated prices. The summaries list the cost delta and percentage of price delta of each bid compared to the lowest price bid. The summaries indicate the payment terms agreed to with each bidder and include the cost of differing payment terms among the bidders. In the summaries, “M30” stands for monthly payments due on the last day of the month following the month of service, “M20” stands for monthly payments due on the 20th of the month following the month of service, and “BI-MO” stands for bi-monthly payment terms.

Pricing exhibits:

- G1 Bids, 6 Month Period
- Non-G1 Bids, 6 Month Period
- G1 Summary Pricing
- Non-G1 Summary Pricing

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
Pricing Comparison

Bids for Small Customers (Asset 11451) - FINAL
Default Service Requirements for 6 Months ($/MWH)

Month of Service	Eval Loads (MWh)	
Aug-24	37,786	[redacted]
Sep-24	31,208	
Oct-24	25,200	
Nov-24	24,938	
Dec-24	31,824	
Jan-25	37,284	
PERIOD	188,242	
POWER COST ($000)		
PAYMENT TERMS		
INT. COST ($000)		
TOTAL COST ($000)		
COST DELTA ($000)		
PRICE RANKING		
PERCENT DELTA		

REDACTED

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
Pricing Comparison

Bids for Medium Customers (Asset 11452) - FINAL
90% Default Service Requirements for 6 Months ($/MWH)

Month of Service	Eval Loads (MWh)	
Aug-24	12,888	[redacted]
Sep-24	11,385	
Oct-24	9,926	
Nov-24	9,524	
Dec-24	10,638	
Jan-25	11,652	
PERIOD	66,013	
POWER COST ($000)		
PAYMENT TERMS		
INT. COST ($000)		
TOTAL COST ($000)		
COST DELTA ($000)		
PRICE RANKING		
PERCENT DELTA		

REDACTED

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
Pricing Comparison

Bids for Large Customers (Asset 10019)- FINAL
100% DS Requirements for 6 Months ($/MWH) - Variable Price Adder

Month of Service	Evaluation Loads (MWh)	
Aug-24	1,427	[redacted]
Sep-24	1,319	
Oct-24	1,195	
Nov-24	1,131	
Dec-24	1,172	
Jan-25	1,190	
PERIOD	7,434	
POWER COST ($000)		
PAYMENT TERMS		
INT. COST ($000)		
TOTAL COST ($000)		
COST DELTA ($000)		
PRICE RANKING		
PERCENT DELTA		

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
Historical Pricing Comparison, G1 Customers
(Pricing includes Fixed Adder and Energy)

	G1 Supplier	G1 Pricing ($/MWH)	G1 Purchases (MWH)	Wtd Avg Price	Change Prior Period	Change Prior Year
Nov-19	DYNEGY	$ 70.05	3,342			
Dec-19	NEXTERA	$ 76.10	3,586	$ 68.36	32.8%	-22.3%
Jan-20	NEXTERA	$ 58.71	3,461			
Feb-20	NEXTERA	$ 55.62	3,466			
Mar-20	NEXTERA	$ 51.14	3,478	$ 53.96	-21.1%	-29.3%
Apr-20	NEXTERA	$ 55.21	3,229			
May-20	NEXTERA	$ 53.79	3,244			
Jun-20	HQUS	$ 44.16	4,559	$ 47.14	-12.6%	-17.5%
Jul-20	HQUS	$ 45.54	4,995			
Aug-20	HQUS	$ 48.10	4,678			
Sep-20	HQUS	$ 45.30	4,726	$ 48.62	3.1%	-5.6%
Oct-20	HQUS	$ 53.06	4,073			
Nov-20	HQUS	$ 50.41	3,690			
Dec-20	EXELON	$ 71.52	4,667	$ 66.69	37.2%	-2.4%
Jan-21	EXELON	$ 75.40	4,304			
Feb-21	EXELON	$ 106.15	4,405			
Mar-21	EXELON	$ 67.56	4,261	$ 76.71	15.0%	42.2%
Apr-21	EXELON	$ 55.60	4,294			
May-21	EXELON	$ 52.84	4,622			
Jun-21	EXELON	$ 61.55	3,997	$ 58.04	-24.3%	23.1%
Jul-21	EXELON	$ 60.29	4,449			
Aug-21	EXELON	$ 74.57	4,622			
Sep-21	EXELON	$ 70.56	4,297	$ 74.71	28.7%	53.7%
Oct-21	EXELON	$ 79.50	3,856			
Nov-21	EXELON	$ 82.66	3,815			
Dec-21	NEXTERA	$ 82.76	4,387	$112.96	51.2%	69.4%
Jan-22	NEXTERA	$ 172.74	4,150			
Feb-22	NEXTERA	$ 136.82	4,183			
Mar-22	NEXTERA	$ 89.18	4,206	$102.70	-9.1%	33.9%
Apr-22	NEXTERA	$ 82.49	4,247			
May-22	NEXTERA	$ 97.25	4,102			
Jun-22	NEXTERA	$ 94.24	5,022	$103.65	0.9%	78.6%
Jul-22	NEXTERA	$ 117.09	5,465			
Aug-22	NEXTERA	$ 120.18	5,785			
Sep-22	NEXTERA	$ 83.91	5,293	$ 94.65	-8.7%	26.7%
Oct-22	NEXTERA	$ 76.14	4,910			
Nov-22	NEXTERA	$ 91.19	4,756			
Dec-22	HQUS	$ 156.47	4,471	$110.50	16.8%	-2.2%
Jan-23	HQUS	$ 86.17	4,670			
Feb-23	HQUS	$ 103.56	4,557			
Mar-23	HQUS	$ 66.04	4,555	$ 78.15	-29.3%	-23.9%
Apr-23	HQUS	$ 64.19	4,341			
May-23	HQUS	$ 58.06	4,614			
Jun-23	HQUS	$ 66.59	4,698	$ 64.44	-17.5%	-37.8%
Jul-23	HQUS	$ 68.16	5,190			
Aug-23	CECG	$ 54.59	5,037			
Sep-23	CECG	$ 64.81	4,399	$ 56.82	-11.8%	-40.0%
Oct-23	CECG	$ 51.15	4,220			
Nov-23	CECG	$ 65.81	3,827			
Dec-23	CECG	$ 71.87	4,110	$ 80.32	41.4%	-27.3%
Jan-24	CECG	$ 102.11	4,141			
Feb-24	NEM		3,547			
Mar-24	NEM	[redacted]	3,447	[redacted]		
Apr-24	NEM		3,366			
May-24	NEM		3,359			
Jun-24	NEM	N/A	3,726	N/A	N/A	N/A
Jul-24	NEM		4,097			
Aug-24	NEM		1,427			
Sep-24	NEM	N/A	1,319	N/A	N/A	N/A
Oct-24	NEM		1,195			
Nov-24	NEM		1,131			
Dec-24	NEM	N/A	1,172	N/A	N/A	N/A
Jan-25	NEM		1,190			

G1 Legal Estimates for this RFP: $0

Note: GIS costs are booked to a common account, not by customer group.

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
Historical Pricing Comparison, Non-G1 Customers

	Load Requirements	Block A	Block B	Block C	Block D	Block A	Block B	Block C	Block D	Non-G1 Pricing ($/MWH)	Non-G1 Purchases (MWH)	Wtd Avg Price	Change Prior Period	Change Prior Year
Dec-19	100%	NEXTERA	(Small)	NEXTERA	(Medium)	$ 114.30	(Small)	$ 104.82	(Medium)	$ 109.56	55,151	$ 88.55	28.3%	-15.0%
Jan-20		NEXTERA	(Small)	NEXTERA	(Medium)	$ 106.82	(Small)	$ 100.94	(Medium)	$ 103.88	64,846			
Feb-20		NEXTERA	(Small)	NEXTERA	(Medium)	$ 107.17	(Small)	$ 102.83	(Medium)	$ 105.00	61,007			
Mar-20		NEXTERA	(Small)	NEXTERA	(Medium)	$ 91.94	(Small)	$ 72.50	(Medium)	$ 82.22	54,444			
Apr-20		NEXTERA	(Small)	NEXTERA	(Medium)	$ 60.41	(Small)	$ 47.11	(Medium)	$ 53.76	50,230			
May-20		NEXTERA	(Small)	NEXTERA	(Medium)	$ 73.62	(Small)	$ 57.29	(Medium)	$ 65.46	46,070			
Jun-20	100%	NEXTERA	(Small)	EXELON	(Medium)	$ 54.13	(Small)	$ 40.76	(Medium)	$ 47.45	52,981	$ 50.42	-43.1%	-26.9%
Jul-20		NEXTERA	(Small)	EXELON	(Medium)	$ 51.78	(Small)	$ 45.48	(Medium)	$ 48.63	65,465			
Aug-20		NEXTERA	(Small)	EXELON	(Medium)	$ 51.71	(Small)	$ 43.85	(Medium)	$ 47.78	61,604			
Sep-20		NEXTERA	(Small)	EXELON	(Medium)	$ 56.11	(Small)	$ 43.52	(Medium)	$ 49.82	56,863			
Oct-20		NEXTERA	(Small)	EXELON	(Medium)	$ 58.43	(Small)	$ 44.42	(Medium)	$ 51.43	48,292			
Nov-20		NEXTERA	(Small)	EXELON	(Medium)	$ 64.21	(Small)	$ 54.14	(Medium)	$ 59.18	48,417			
Dec-20	100%	NEXTERA	(Small)	EXELON	(Medium)	$ 75.09	(Small)	$ 74.45	(Medium)	$ 74.77	62,281	$ 74.41	47.6%	-16.0%
Jan-21		NEXTERA	(Small)	EXELON	(Medium)	$ 89.89	(Small)	$ 86.56	(Medium)	$ 88.23	62,839			
Feb-21		NEXTERA	(Small)	EXELON	(Medium)	$ 91.45	(Small)	$ 85.85	(Medium)	$ 88.65	62,244			
Mar-21		NEXTERA	(Small)	EXELON	(Medium)	$ 72.31	(Small)	$ 67.29	(Medium)	$ 69.80	54,524			
Apr-21		NEXTERA	(Small)	EXELON	(Medium)	$ 65.17	(Small)	$ 57.71	(Medium)	$ 61.44	51,458			
May-21		NEXTERA	(Small)	EXELON	(Medium)	$ 59.83	(Small)	$ 52.82	(Medium)	$ 56.33	47,389			
Jun-21	100%	NEXTERA	(Small)	NEXTERA	(Medium)	$ 58.92	(Small)	$ 46.27	(Medium)	$ 52.60	50,816	$ 54.90	-26.2%	8.9%
Jul-21		NEXTERA	(Small)	NEXTERA	(Medium)	$ 77.12	(Small)	$ 60.39	(Medium)	$ 68.76	56,487			
Aug-21		NEXTERA	(Small)	NEXTERA	(Medium)	$ 51.70	(Small)	$ 47.96	(Medium)	$ 49.83	67,064			
Sep-21		NEXTERA	(Small)	NEXTERA	(Medium)	$ 35.89	(Small)	$ 34.54	(Medium)	$ 35.22	60,128			
Oct-21		NEXTERA	(Small)	NEXTERA	(Medium)	$ 65.18	(Small)	$ 47.96	(Medium)	$ 56.57	45,181			
Nov-21		NEXTERA	(Small)	NEXTERA	(Medium)	$ 79.00	(Small)	$ 63.80	(Medium)	$ 71.40	47,466			
Dec-21	100%	NEXTERA	(Small)	NEXTERA	(Medium)	$ 187.14	(Small)	$ 174.86	(Medium)	$ 181.00	59,483	$ 149.23	171.8%	100.5%
Jan-22		NEXTERA	(Small)	NEXTERA	(Medium)	$ 222.00	(Small)	$ 205.05	(Medium)	$ 213.53	61,901			
Feb-22		NEXTERA	(Small)	NEXTERA	(Medium)	$ 214.13	(Small)	$ 199.81	(Medium)	$ 206.97	59,300			
Mar-22		NEXTERA	(Small)	NEXTERA	(Medium)	$ 137.90	(Small)	$ 121.89	(Medium)	$ 129.90	54,283			
Apr-22		NEXTERA	(Small)	NEXTERA	(Medium)	$ 66.20	(Small)	$ 57.09	(Medium)	$ 61.65	51,132			
May-22		NEXTERA	(Small)	NEXTERA	(Medium)	$ 75.43	(Small)	$ 58.79	(Medium)	$ 67.11	45,865			
Jun-22	100%	HQUS	(Small)	HQUS	(Medium)	$ 79.98	(Small)	$ 72.97	(Medium)	$ 76.48	50,014	$ 88.06	-41.0%	60.4%
Jul-22		HQUS	(Small)	HQUS	(Medium)	$ 88.51	(Small)	$ 84.08	(Medium)	$ 86.30	62,434			
Aug-22		HQUS	(Small)	HQUS	(Medium)	$ 90.42	(Small)	$ 85.79	(Medium)	$ 88.11	70,399			
Sep-22		HQUS	(Small)	HQUS	(Medium)	$ 83.93	(Small)	$ 75.43	(Medium)	$ 79.68	56,477			
Oct-22		HQUS	(Small)	HQUS	(Medium)	$ 88.05	(Small)	$ 78.58	(Medium)	$ 83.32	47,477			
Nov-22		HQUS	(Small)	HQUS	(Medium)	$ 119.28	(Small)	$ 111.03	(Medium)	$ 115.16	51,110			
Dec-22	100%	EXELON	(Small)	EXELON	(Medium)	$ 308.37	(Small)	$ 307.64	(Medium)	$ 308.01	57,434	$ 237.28	169.5%	59.0%
Jan-23		EXELON	(Small)	EXELON	(Medium)	$ 382.82	(Small)	$ 388.88	(Medium)	$ 385.85	63,602			
Feb-23		EXELON	(Small)	EXELON	(Medium)	$ 362.84	(Small)	$ 370.16	(Medium)	$ 366.50	63,237			
Mar-23		EXELON	(Small)	EXELON	(Medium)	$ 227.02	(Small)	$ 227.99	(Medium)	$ 227.51	57,239			
Apr-23		EXELON	(Small)	EXELON	(Medium)	$ 149.61	(Small)	$ 147.80	(Medium)	$ 148.71	51,116			
May-23		EXELON	(Small)	EXELON	(Medium)	$ 130.53	(Small)	$ 127.81	(Medium)	$ 129.17	48,733			
Jun-23		EXELON	(Small)	EXELON	(Medium)	$ 123.33	(Small)	$ 127.07	(Medium)	$ 125.20	49,611			
Jul-23		EXELON	(Small)	EXELON	(Medium)	$ 143.72	(Small)	$ 146.13	(Medium)	$ 144.93	62,455			
Aug-23	100%	NEXTERA	(Small)	NEXTERA	(Medium)	$ 80.43	(Small)	$ 73.28	(Medium)	$ 76.86	69,228	$ 116.77	-50.8%	32.6%
Sep-23		NEXTERA	(Small)	NEXTERA	(Medium)	$ 61.65	(Small)	$ 56.24	(Medium)	$ 58.95	54,354			
Oct-23		NEXTERA	(Small)	NEXTERA	(Medium)	$ 56.59	(Small)	$ 53.55	(Medium)	$ 55.07	47,839			
Nov-23		NEXTERA	(Small)	NEXTERA	(Medium)	$ 86.36	(Small)	$ 90.33	(Medium)	$ 88.35	47,800			
Dec-23		NEXTERA	(Small)	NEXTERA	(Medium)	$ 173.48	(Small)	$ 174.36	(Medium)	$ 173.92	57,022			
Jan-24		NEXTERA	(Small)	NEXTERA	(Medium)	$ 228.21	(Small)	$ 233.56	(Medium)	$ 230.89	60,971			
Feb-24	100%	CECG	(Small)	CECG	(Medium)	[redacted]	(Small)	[redacted]	(Medium)	[redacted]	54,260	[redacted]	[redacted]	[redacted]
Mar-24		CECG	(Small)	CECG	(Medium)	[redacted]	(Small)	[redacted]	(Medium)	[redacted]	51,186	[redacted]	[redacted]	[redacted]
Apr-24		CECG	(Small)	CECG	(Medium)	[redacted]	(Small)	[redacted]	(Medium)	[redacted]	44,277	[redacted]	[redacted]	[redacted]
May-24		CECG	(Small)	CECG	(Medium)	[redacted]	(Small)	[redacted]	(Medium)	[redacted]	41,134	[redacted]	[redacted]	[redacted]
Jun-24		CECG	(Small)	CECG	(Medium)	[redacted]	(Small)	[redacted]	(Medium)	[redacted]	46,927	[redacted]	[redacted]	[redacted]
Jul-24		CECG	(Small)	CECG	(Medium)	[redacted]	(Small)	[redacted]	(Medium)	[redacted]	58,001	[redacted]	[redacted]	[redacted]
Aug-24	90%	CECG	(Small)	CECG	(Medium)	[redacted]	(Small)	[redacted]	(Medium)	[redacted]	50,675	[redacted]	[redacted]	[redacted]
Sep-24		CECG	(Small)	CECG	(Medium)	[redacted]	(Small)	[redacted]	(Medium)	[redacted]	42,593	[redacted]	[redacted]	[redacted]
Oct-24		CECG	(Small)	CECG	(Medium)	[redacted]	(Small)	[redacted]	(Medium)	[redacted]	35,126	[redacted]	[redacted]	[redacted]
Nov-24		CECG	(Small)	CECG	(Medium)	[redacted]	(Small)	[redacted]	(Medium)	[redacted]	34,462	[redacted]	[redacted]	[redacted]
Dec-24		CECG	(Small)	CECG	(Medium)	[redacted]	(Small)	[redacted]	(Medium)	[redacted]	42,462	[redacted]	[redacted]	[redacted]
Jan-25		CECG	(Small)	CECG	(Medium)	[redacted]	(Small)	[redacted]	(Medium)	[redacted]	48,937	[redacted]	[redacted]	[redacted]

Non-G1 Legal Estimates for this RFP: **$0**

Note: GIS costs are booked to a common account, not by customer group.

Tab A(3). UES RECs Procurement Summary

The third item attached to this Comparison of Bids is a summary of REC purchases for the 2024 compliance year. This table details the Class of RECs purchased, the quantity purchased, the cost per REC, and the transaction date. The table also describes if the purchase was made through the REC RFP process or if the RECs were acquired independent of the REC RFP process.

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
Summary of REC Purchases for 2024 RPS Compliance

Transaction Date	Process	Vintage	Class I		Class 1 Thermal		Class II		Class III		Class IV	
			Volume	Price	Volume	Price	Volume	Price	Volume	Price	Volume	Price
[redacted]												
Purchase Summary		2024	[redacted]									

Estimated Requirements		2024	[redacted]
Percentage Purchased[1]		2024	

Notes:

1. Percentage Purchased **excludes** banked RECs from prior years and Class I and Class II Net Metering Credits. Purchased RECs have been contracted for but may not yet have been transferred to the Company's GIS subaccount.

Tab A(4). Comparisons to NYMEX Futures

The fourth item attached to this Comparison of Bids compares the winning final bids to both the NYMEX over-the-counter futures contracts for ISO New England averaged on-and-off peak electric futures ("NYMEX ISO") and the NYMEX natural gas futures contracts at Henry Hub ("NYMEX NG"). These tables generally show the proportion of the bid price that is associated with energy, typically the largest driver of wholesale costs, as opposed to other non-energy costs embedded in a bid price such as capacity and ancillary services along with supplier risk premiums and supplier margin. Lower bid to NYMEX ratios can be associated with a price for which energy comprises a greater component; conversely, higher bid to NYMEX ratios indicate the price is comprised of an increasing proportion of non-energy components. The ratio of winning bid prices to the two NYMEX contracts was calculated for the upcoming default service period and is compared to the current and prior procurement period (February 1, 2024 – July 31, 2024 and August 1, 2023 – January 31, 2024).

Hypothetical prices were then calculated by applying the current NYMEX pricing to the ratio of winning bid prices to NYMEX prices observed in previous procurements. These are what the prices would have been if the final bid price to NYMEX ratio was the same as the prior period to which it is being compared. A comparison was then made between the current winning bid prices and the hypothetical prices. Results of the comparison show that the current ratio of final bid prices to NYMEX ISO is [redacted] than the ratio of final bid prices to NYMEX ISO during the 6-month period a year ago, and is [redacted] than the ratio for the current 6-month period of February 1, 2024 – July 31, 2024. These comparisons indicate that the winning bids were consistent to prior winning bids, but for the changes in underlying market prices. The Company relied on these results in part in determining the reasonableness of the winning bids.

For natural gas, the comparison shows that current ratio of final bid prices to NYMEX NG is [redacted] than the ratio of final bid prices during the 6-month period a year ago, and [redacted] than the ratio for the current 6-month period of February 1, 2024 – July 31, 2024. Please note that the Company relies more on the NYMEX ISO comparison than the NYMEX NG comparison because the ISO comparison reflects regional New England prices while the NG comparison reflects national prices which do not reflect the incremental costs of regional supply.

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
Comparison of Winning Bids to NYMEX Futures - Non G1 Customers

UES 6-Month Non-G1 Customer Default Service Bids versus NYMEX OTC New England On-Peak Electric Futures (ISO)

	RFP for Service Beginning August 1, 2024				RFP for Service Beginning August 1, 2023					
	Evaluation Loads	$/MWH Final Bid [redacted]	$/MWH NYMEX ISO [redacted]	Ratio of Final Bid to NYMEX ISO	Evaluation Loads	$/MWH Final Bid 6/6/23	$/MWH NYMEX ISO 6/5/23	Ratio of Final Bid to NYMEX ISO	$/MWH Final Bid Price	$/MWH Calculation Result
Aug-23					69,228	[redacted]	[redacted]	[redacted]		
Sep-23					54,354	[redacted]	[redacted]	[redacted]		
Oct-23					47,839	[redacted]	[redacted]	[redacted]		
Nov-23					47,800	[redacted]	[redacted]	[redacted]		
Dec-23					57,022	[redacted]	[redacted]	[redacted]		
Jan-24					60,971	[redacted]	[redacted]	[redacted]		
Aug-24	50,675	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
Sep-24	42,593	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
Oct-24	35,126	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
Nov-24	34,462	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
Dec-24	42,462	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
Jan-25	48,937	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
PERIOD	254,255	[redacted]	[redacted]	[redacted]	337,213	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
								Final Bid Price v. Calculation Result	[redacted]	[redacted]

Note: NYMEX quotes list prior day close since bids were due at 10:00 am. Bids shown are winning bids and include the cost of capacity.

REDACTED

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
Comparison of Winning Bids to NYMEX Futures - Non G1 Customers

UES 6-Month Non-G1 Customer Default Service Bids versus NYMEX OTC New England On-Peak Electric Futures (ISO)

	RFP for Service Beginning August 1, 2024				RFP for Service Beginning February 1, 2024					
	Evaluation Loads	$/MWH Final Bid [redacted]	$/MWH NYMEX ISO [redacted]	Ratio of Final Bid to NYMEX ISO	Evaluation Loads	$/MWH Final Bid 11/28/23	$/MWH NYMEX ISO 11/27/23	Ratio of Final Bid to NYMEX ISO	$/MWH Final Bid Price	$/MWH Calculation Result
Feb-24					54,260	[redacted]				
Mar-24					51,186					
Apr-24					44,277					
May-24					41,134					
Jun-24					46,927					
Jul-24					58,001					
Aug-24	50,675	[redacted]							[redacted]	
Sep-24	42,593									
Oct-24	35,126									
Nov-24	34,462									
Dec-24	42,462									
Jan-25	48,937									
PERIOD	254,255				295,786	[redacted]	[redacted]	[redacted]		
						Final Bid Price v. Calculation Result				

Note: NYMEX quotes list prior day close since bids were due at 10:00 am. Bids shown are winning bids and include the cost of capacity.

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
Comparison of Winning Bids to NYMEX Futures - Non G1 Customers

UES 6-Month Non-G1 Customer Default Service Bids versus NYMEX OTC Natural Gas (NG) Henry Hub Futures

	RFP for Service Beginning August 1, 2024				RFP for Service Beginning August 1, 2023					
	Evaluation Loads	$/MWH Final Bid [redacted]	$/mmbtu NYMEX NG [redacted]	Ratio of Final Bid to NYMEX NG	Evaluation Loads	$/MWH Final Bid 6/6/23	$/mmbtu NYMEX NG 6/5/23	Ratio of Final Bid to NYMEX NG	$/MWH Final Bid Price	$/MWH Calculation Result
Aug-23					69,228	[redacted]				
Sep-23					54,354	[redacted]				
Oct-23					47,839	[redacted]				
Nov-23					47,800	[redacted]				
Dec-23					57,022	[redacted]				
Jan-24					60,971	[redacted]			[redacted]	
Aug-24	50,675	[redacted]							[redacted]	
Sep-24	42,593	[redacted]							[redacted]	
Oct-24	35,126	[redacted]							[redacted]	
Nov-24	34,462	[redacted]							[redacted]	
Dec-24	42,462	[redacted]							[redacted]	
Jan-25	48,937	[redacted]							[redacted]	
PERIOD	254,255	[redacted]			337,213	[redacted]	[redacted]	[redacted]	[redacted]	
						Final Bid Price v. Calculation Result			[redacted]	

Note: NYMEX quotes list prior day close since bids were due at 10:00 am. Bids shown are winning bids and include the cost of capacity.

REDACTED

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
Comparison of Winning Bids to NYMEX Futures - Non G1 Customers

UES 6-Month Non-G1 Customer Default Service Bids versus NYMEX OTC Natural Gas (NG) Henry Hub Futures

	RFP for Service Beginning August 1, 2024				RFP for Service Beginning February 1, 2024					
	Evaluation Loads	$/MWH Final Bid [redacted]	$/mmbtu NYMEX NG [redacted]	Ratio of Final Bid to NYMEX NG	Evaluation Loads	$/MWH Final Bid 11/28/23	$/mmbtu NYMEX NG 11/27/23	Ratio of Final Bid to NYMEX NG	$/MWH Final Bid Price	$/MWH Calculation Result
Feb-24					54,260	[redacted]	[redacted]	[redacted]		
Mar-24					51,186	[redacted]	[redacted]	[redacted]		
Apr-24					44,277	[redacted]	[redacted]	[redacted]		
May-24					41,134	[redacted]	[redacted]	[redacted]		
Jun-24					46,927	[redacted]	[redacted]	[redacted]		
Jul-24					58,001	[redacted]	[redacted]	[redacted]		
Aug-24	50,675	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
Sep-24	42,593	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
Oct-24	35,126	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
Nov-24	34,462	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
Dec-24	42,462	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
Jan-25	48,937	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
PERIOD	254,255	[redacted]	[redacted]	[redacted]	295,786	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Final Bid Price v. Calculation Result [redacted]

Note: NYMEX quotes list prior day close since bids were due at 10:00 am. Bids shown are winning bids and include the cost of capacity.

Tab A(5). Financial Security Requirements

The fifth item attached to this Comparison of Bids contains a summary of each bidder's financial security requirements of UES and each bidder's own provision of financial security and creditworthiness. Items listed include the amount of Shareholder Equity (if any) to be used as a credit test for UES, payment terms and estimated interest costs associated with accelerated payments for each service bid, agreed upon corporate guaranty amounts, credit ratings for suppliers or their parent companies and other credit support as may be required.

Also attached are sheets that describe the credit rating definitions used by Standard & Poor's and by Moody's.

REDACTED

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
Summary of Financial Security Requirements

Financial Security provided by Seller

Payment Terms, assoc. interest cost ($000)				Unitil Guaranty			Other Credit Support	Rated Entity	Supplier Debt Ratings			Guaranty Support			Other Credit Support
Terms	Small	Med	Large	Small	Med	Large			S&P	Moody	Fitch	Small	Med	Large	
[redacted]															

Note1: For suppliers requiring bi-monthly (BI-MO) or net 20 (M20) payment, the value shown represents the incremental borrowing costs compared to end of month following service payments (M30).

Note2: Creditworthiness of all Suppliers contingent upon Investment Grade Status of Rated Entity.

Note3: "No Material Impairment" means a party is creditworthy so long as the other party does not have a reasonable belief it has become materially impaired.

Standard & Poor's Ratings Definitions
Long-Term Issue Credit Ratings

Issue credit ratings are based, in varying degrees, on S&P Global Ratings' analysis of the following considerations:

- The likelihood of payment--the capacity and willingness of the obligor to meet its financial commitments on an obligation in accordance with the terms of the obligation;
- The nature and provisions of the financial obligation, and the promise we impute; and
- The protection afforded by, and relative position of, the financial obligation in the event of a bankruptcy, reorganization, or other arrangement under the laws of bankruptcy and other laws affecting creditors' rights.

Issue ratings are an assessment of default risk but may incorporate an assessment of relative seniority or ultimate recovery in the event of default. Junior obligations are typically rated lower than senior obligations, to reflect the lower priority in bankruptcy, as noted above. (Such differentiation may apply when an entity has both senior and subordinated obligations, secured and unsecured obligations, or operating company and holding company obligations.)

Long-Term Issue Credit Ratings*	
Category	**Definition**
AAA	An obligation rated 'AAA' has the highest rating assigned by S&P Global Ratings. The obligor's capacity to meet its financial commitments on the obligation is extremely strong.
AA	An obligation rated 'AA' differs from the highest-rated obligations only to a small degree. The obligor's capacity to meet its financial commitments on the obligation is very strong.
A	An obligation rated 'A' is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories. However, the obligor's capacity to meet its financial commitments on the obligation is still strong.
BBB	An obligation rated 'BBB' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to weaken the obligor's capacity to meet its financial commitments on the obligation.
BB, B, CCC, CC, and C	Obligations rated 'BB', 'B', 'CCC', 'CC', and 'C' are regarded as having significant speculative characteristics. 'BB' indicates the least degree of speculation and 'C' the highest. While such obligations will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposure to adverse conditions.
BB	An obligation rated 'BB' is less vulnerable to nonpayment than other speculative issues. However, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions that could lead to the obligor's inadequate capacity to meet its financial commitments on the obligation.
B	An obligation rated 'B' is more vulnerable to nonpayment than obligations rated 'BB', but the obligor currently has the capacity to meet its financial commitments on the obligation. Adverse business, financial, or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitments on the obligation.

CCC	An obligation rated 'CCC' is currently vulnerable to nonpayment and is dependent upon favorable business, financial, and economic conditions for the obligor to meet its financial commitments on the obligation. In the event of adverse business, financial, or economic conditions, the obligor is not likely to have the capacity to meet its financial commitments on the obligation.
CC	An obligation rated 'CC' is currently highly vulnerable to nonpayment. The 'CC' rating is used when a default has not yet occurred but S&P Global Ratings expects default to be a virtual certainty, regardless of the anticipated time to default.
C	An obligation rated 'C' is currently highly vulnerable to nonpayment, and the obligation is expected to have lower relative seniority or lower ultimate recovery compared with obligations that are rated higher.
D	An obligation rated 'D' is in default or in breach of an imputed promise. For non-hybrid capital instruments, the 'D' rating category is used when payments on an obligation are not made on the date due, unless S&P Global Ratings believes that such payments will be made within five business days in the absence of a stated grace period or within the earlier of the stated grace period or 30 calendar days. The 'D' rating also will be used upon the filing of a bankruptcy petition or the taking of similar action and where default on an obligation is a virtual certainty, for example due to automatic stay provisions. An obligation's rating is lowered to 'D' if it is subject to a distressed exchange offer.
NR	This indicates that no rating has been requested, or that there is insufficient information on which to base a rating, or that S&P Global Ratings does not rate a particular obligation as a matter of policy.
*The ratings from 'AA' to 'CCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.	

Source: Use the following link. Select “Ratings Definitions” under the **Regulatory** category. Ratings were updated June 26, 2017.
http://www.standardandpoors.com/en_US/web/guest/home?pagename=sp/Page/FixedIncomeRatingsCriteriaPg&r=1&l=EN&b=2

Moody's Long-Term Rating Definitions
Long-Term Obligation Ratings

Moody's long-term obligation ratings are opinions of the relative credit risk of fixed-income obligations with an original maturity of one year or more. They address the possibility that a financial obligation will not be honored as promised. Such ratings reflect both the likelihood of default and any financial loss suffered in the event of default.

Aaa	Obligations rated Aaa are judged to be of the highest quality, with minimal credit risk.
Aa	Obligations rated Aa are judged to be of high quality and are subject to very low credit risk.
A	Obligations rated A are considered upper-medium grade and are subject to low credit risk.
Baa	Obligations rated Baa are subject to moderate credit risk. They are considered medium-grade and as such may possess certain speculative characteristics.
Ba	Obligations rated Ba are judged to have speculative elements and are subject to substantial credit risk.
B	Obligations rated B are considered speculative and are subject to high credit risk.
Caa	Obligations rated Caa are judged to be of poor standing and are subject to very high credit risk.
Ca	Obligations rated Ca are highly speculative and are likely in, or very near, default, with some prospect of recovery of principal and interest.
C	Obligations rated C are the lowest rated class of bonds and are typically in default, with little prospect for recovery of principal or interest.

Note: Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Source: After registering on Moody's website and agreeing to their Terms of Use, use the following link:

http://www.moodys.com/moodys/cust/AboutMoodys/AboutMoodys.aspx?topic=rdef&subtopic=moodys%20credit%20ratings&title=Long+Term+Obligation+Ratings.htm

Tab A(6). Proposal Submission Forms

The sixth item attached to this Comparison of Bids contains the non-price information provided by each bidder upon submission of the proposal submission form, which is identified as Attachment A to the RFP.

[redacted]

APPENDIX A: PROPOSAL SUBMISSION FORM

1. General Information

Name of Respondent	[redacted]
Name of Parent or Guarantor (if any)	
Principal contact person < Name < Title < Company < Mailing address < Telephone number (office) < Telephone number (cell) < Fax number < E-mail address	
Secondary contact person (if any) < Name < Title < Company < Mailing address < Telephone number (office) < Telephone number (cell) < Fax number < E-mail address	
Legal form of business organization of Respondent (e.g., sole proprietorship, partnership, limited partnership, joint venture, or corporation)	
State(s) of incorporation, residency or organization Indicate whether Respondent is in good standing in all states in which Respondent is authorized to do business and, if not, which states and the reason it is not.	

[redacted]

If Respondent is a partnership, the names of all general and limited partners. If Respondent is a limited liability company, the names of all direct owners.	[redacted]
Description of Respondent and all affiliated entities and joint ventures transacting business in the energy sector.	

2. Financial Information

Please provide the following for Respondent and/or Parent/Guarantor (as appropriate)	Respondent	Parent/Guarantor
Current debt ratings, including names of rating agencies and dates of ratings. If entity is not rated, please indicate.	[redacted]	
Date last fiscal year ended.		
Total revenue for the most recent fiscal year.		
Total net income for the most recent fiscal year.		

[redacted]

Total assets as of the close of the previous fiscal year.	[redacted]
DUNS Number and Federal Tax ID.	
Please provide a copy of the most recent financials including balance sheet, income statement and cash flow statement.	

3. Defaults and Adverse Situations

Describe, in detail, any situation in which Respondent (either alone or as part of a joint venture), or an affiliate of Respondent, defaulted or was deemed to be in noncompliance of its contractual obligations to deliver energy and/or capacity at wholesale within the past five years. Explain the situation, its outcome and all other relevant facts associated with the event described. Identify the name, title and telephone number of the principal manager of the customer/client who asserted the event of default or noncompliance.	[redacted]
Has Respondent, or any affiliate of Respondent, in the last five years, (a) consented to the appointment of, or was taken in possession by, a receiver, trustee, custodian or liquidator of a substantial part of its assets,	

[redacted]

(b) filed a bankruptcy petition in any bankruptcy court proceeding, (c) answered, consented or sought relief under any bankruptcy or similar law or failed to obtain a dismissal of an involuntary petition, (d) admitted in writing of its inability to pay its debts when due, (e) made a general assignment for the benefit of creditors, (f) was the subject of an involuntary proceeding seeking to adjudicate that Party bankrupt or insolvent, (g) sought reorganization, arrangement, adjustment, or composition of it or its debt under any law relating to bankruptcy, insolvency or reorganization or relief of debtors.	[redacted]
Describe any facts presently known to Respondent that might adversely affect its ability to provide the service(s) bid herein as provided for in the Request for Proposals.	

4. NEPOOL and Power Supply Experience

Is Respondent a member of NEPOOL?	[redacted]
Please list Respondent's NEPOOL Participant ID.	
If Respondent is NOT a NEPOOL member, list the name and Participant ID of the NEPOOL member who will carry Respondent's obligations in its settlement account. Please provide a supporting statement and contact information from such member.	
Please describe Respondent's experience and record of performance in the areas of power marketing, brokering, sales, and/or contracting, for the last five years within NEPOOL and/or the New England region.	
Has Respondent previously provided Default Service to UES?	

[redacted]

If response is "NO", please provide references as requested below. -- Please provide three references (name, title and contact information) who have contracted with the Respondent for load-following services or who can attest to Respondent's ability in the areas of power supply portfolio management within the past 2 years.	[redacted]

[redacted]

5. Non Price Terms

Does Respondent extend sufficient financial credit to UES to facilitate the transactions sought via this RFP?	[redacted]
Please indicate what, if any, financial security requirements Respondent has of UES in order to secure the extension of credit. Please attach any proposed contractual language.	
Does Respondent agree that the obligations of both parties are subject to and conditioned upon the NHPUC's approval of the retail rates derived from the transaction sought in this solicitation?	
Please list all regulatory approvals required before service can commence.	
Is Respondent willing to enter into contractual terms substantially as proposed in the Power Supply Agreement contained in Appendix B?	
Provide any proposed modifications to the Power Supply Agreement provided in Appendix B or to the PSA Amendment in Appendix B1. Please briefly list issues here and provide proposed language changes in the document using the "track changes" feature of Microsoft Word, or other reviewable revision marking process.	

[redacted]

APPENDIX A: PROPOSAL SUBMISSION FORM

1. General Information

Name of Respondent	[redacted]
Name of Parent or Guarantor (if any)	
Principal contact person < Name < Title < Company < Mailing address < Telephone number (office) < Telephone number (cell) < Fax number < E-mail address	
Secondary contact person (if any) < Name < Title < Company < Mailing address < Telephone number (office) < Telephone number (cell) < Fax number < E-mail address	
Legal form of business organization of Respondent (e.g., sole proprietorship, partnership, limited partnership, joint venture, or corporation)	
State(s) of incorporation, residency or organization Indicate whether Respondent is in good standing in all states in which Respondent is	

[redacted]

authorized to do business and, if not, which states and the reason it is not.	[redacted]
If Respondent is a partnership, the names of all general and limited partners. If Respondent is a limited liability company, the names of all direct owners.	[redacted]
Description of Respondent and all affiliated entities and joint ventures transacting business in the energy sector.	[redacted]

2. Financial Information

Please provide the following for Respondent and/or Parent/Guarantor (as appropriate)	Respondent	Parent/Guarantor

[redacted]

Current debt ratings, including names of rating agencies and dates of ratings. If entity is not rated, please indicate.	[redacted]
Date last fiscal year ended.	
Total revenue for the most recent fiscal year.	
Total net income for the most recent fiscal year.	
Total assets as of the close of the previous fiscal year.	
DUNS Number and Federal Tax ID.	
Please provide a copy of the most recent financials including balance sheet, income statement and cash flow statement.	

3. Defaults and Adverse Situations

Describe, in detail, any situation in which Respondent (either alone or as part of a joint venture), or an affiliate of Respondent, defaulted or was deemed to be in noncompliance of its contractual obligations	[redacted]

[redacted]

to deliver energy and/or capacity at wholesale within the past five years. Explain the situation, its outcome and all other relevant facts associated with the event described. Identify the name, title and telephone number of the principal manager of the customer/client who asserted the event of default or noncompliance.	[redacted]
Has Respondent, or any affiliate of Respondent, in the last five years, (a) consented to the appointment of, or was taken in possession by, a receiver, trustee, custodian or liquidator of a substantial part of its assets, (b) filed a bankruptcy petition in any bankruptcy court proceeding, (c) answered, consented or sought relief under any bankruptcy or similar law or failed to obtain a dismissal of an involuntary petition, (d) admitted in writing of its inability to pay its debts when due, € made a general assignment for the benefit of creditors, (f) was the subject of an involuntary proceeding seeking to adjudicate that Party bankrupt or insolvent, (g) sought reorganization, arrangement, adjustment, or composition of it or its debt under any law relating to bankruptcy, insolvency or reorganization or relief of debtors.	
Describe any facts presently known to Respondent that might adversely affect its ability to provide the service(s) bid herein as provided for in the Request for Proposals.	

4. NEPOOL and Power Supply Experience

Is Respondent a member of NEPOOL?	[redacted]
Please list Respondent's NEPOOL Participant ID.	

REDACTED

[redacted]

If Respondent is NOT a NEPOOL member, list the name and Participant ID of the NEPOOL member who will carry Respondent's obligations in its settlement account. Please provide a supporting statement and contact information from such member.	[redacted]
Please describe Respondent's experience and record of performance in the areas of power marketing, brokering, sales, and/or contracting, for the last five years within NEPOOL and/or the New England region.	
Has Respondent previously provided Default Service to UES? If response is "NO", please provide references as requested below. -- Please provide three references (name, title and contact information) who have contracted with the Respondent for load-following services or who can attest to Respondent's ability in the areas of power supply portfolio management within the past 2 years.	

5. Non Price Terms

Does Respondent extend sufficient financial credit to UES to facilitate the transactions sought via this RFP?	[redacted]
Please indicate what, if any, financial security requirements Respondent has of UES in order to secure the extension of credit. Please attach any proposed contractual language.	
Does Respondent agree that the obligations of both parties are subject to and conditioned upon the NHPUC's approval of the retail rates derived from the transaction sought in this solicitation?	
Please list all regulatory approvals required before service can commence.	
Is Respondent willing to enter into contractual terms substantially as proposed in the Power Supply Agreement contained in Appendix B?	
Provide any proposed modifications to the Power Supply Agreement provided in Appendix B or to the PSA Amendment in Appendix B1. Please briefly list issues here and provide proposed language changes in the document using the "track changes" feature of Microsoft Word, or other reviewable revision marking process.	

[redacted]

APPENDIX A: PROPOSAL SUBMISSION FORM

1. General Information

Name of Respondent	[redacted]
Name of Parent or Guarantor (if any)	
Principal contact person < Name < Title < Company < Mailing address < Telephone number (office) < Telephone number (cell) < Fax number < E-mail address	
Secondary contact person (if any) < Name < Title < Company < Mailing address < Telephone number (office) < Telephone number (cell) < Fax number < E-mail address	
Legal form of business organization of Respondent (e.g., sole proprietorship, partnership, limited partnership, joint venture, or corporation)	
State(s) of incorporation, residency or organization Indicate whether Respondent is in good standing in all states in which Respondent is authorized to do business and, if not, which states and the reason it is not.	

[redacted]

If Respondent is a partnership, the names of all general and limited partners. If Respondent is a limited liability company, the names of all direct owners.	[redacted]
Description of Respondent and all affiliated entities and joint ventures transacting business in the energy sector.	[redacted]

2. Financial Information

Please provide the following for Respondent and/or Parent/Guarantor (as appropriate)	Respondent	Parent/Guarantor
Current debt ratings, including names of rating agencies and dates of ratings. If entity is not rated, please indicate.	[redacted]	
Date last fiscal year ended.		
Total revenue for the most recent fiscal year.		
Total net income for the most recent fiscal year.		

[redacted]

Total assets as of the close of the previous fiscal year.	[redacted]
DUNS Number and Federal Tax ID.	[redacted]
Please provide a copy of the most recent financials including balance sheet, income statement and cash flow statement.	[redacted]

3. Defaults and Adverse Situations

Describe, in detail, any situation in which Respondent (either alone or as part of a joint venture), or an affiliate of Respondent, defaulted or was deemed to be in noncompliance of its contractual obligations to deliver energy and/or capacity at wholesale within the past five years. Explain the situation, its outcome and all other relevant facts associated with the event described. Identify the name, title and telephone number of the principal manager of the customer/client who asserted the event of default or noncompliance.	[redacted]
Has Respondent, or any affiliate of Respondent, in the last five years, (a) consented to the appointment of, or was taken in possession by, a receiver, trustee, custodian or liquidator of a substantial part of its assets, (b) filed a bankruptcy petition in any bankruptcy court proceeding, (c) answered, consented or sought relief under any bankruptcy or similar law or failed to obtain a dismissal of an involuntary petition, (d)	

[redacted]

admitted in writing of its inability to pay its debts when due, (e) made a general assignment for the benefit of creditors, (f) was the subject of an involuntary proceeding seeking to adjudicate that Party bankrupt or insolvent, (g) sought reorganization, arrangement, adjustment, or composition of it or its debt under any law relating to bankruptcy, insolvency or reorganization or relief of debtors.	[redacted]
Describe any facts presently known to Respondent that might adversely affect its ability to provide the service(s) bid herein as provided for in the Request for Proposals.	

4. NEPOOL and Power Supply Experience

Is Respondent a member of NEPOOL?	[redacted]
Please list Respondent's NEPOOL Participant ID.	
If Respondent is NOT a NEPOOL member, list the name and Participant ID of the NEPOOL member who will carry Respondent's obligations in its settlement account. Please provide a supporting statement and contact information from such member.	
Please describe Respondent's experience and record of performance in the areas of power marketing, brokering, sales, and/or contracting, for the last five years within NEPOOL and/or the New England region.	
Has Respondent previously provided Default Service to UES? If response is "NO", please provide references as requested below. ---	

REDACTED

[redacted]

Please provide three references (name, title and contact information) who have contracted with the Respondent for load-following services or who can attest to Respondent's ability in the areas of power supply portfolio management within the past 2 years.	[redacted]

[redacted]

5. Non Price Terms

Does Respondent extend sufficient financial credit to UES to facilitate the transactions sought via this RFP?	[redacted]
Please indicate what, if any, financial security requirements Respondent has of UES in order to secure the extension of credit. Please attach any proposed contractual language.	
Does Respondent agree that the obligations of both parties are subject to and conditioned upon the NHPUC's approval of the retail rates derived from the transaction sought in this solicitation?	
Please list all regulatory approvals required before service can commence.	
Is Respondent willing to enter into contractual terms substantially as proposed in the Power Supply Agreement contained in Appendix B?	
Provide any proposed modifications to the Power Supply Agreement provided in Appendix B or to the PSA Amendment in Appendix B1. Please briefly list issues here and provide proposed language changes in the document using the "track changes" feature of Microsoft Word, or other reviewable revision marking process.	

[redacted]

APPENDIX A: PROPOSAL SUBMISSION FORM

1. General Information

Name of Respondent	[redacted]
Name of Parent or Guarantor (if any)	[redacted]
Principal contact person < Name < Title < Company < Mailing address < Telephone number (office) < Telephone number (cell) < Fax number < E-mail address	[redacted]
Secondary contact person (if any) < Name < Title < Company < Mailing address < Telephone number (office) < Telephone number (cell) < Fax number < E-mail address	[redacted]
Legal form of business organization of Respondent (e.g., sole proprietorship, partnership, limited partnership, joint venture, or corporation)	[redacted]
State(s) of incorporation, residency or organization Indicate whether Respondent is in good standing in all states in which Respondent is authorized to do business and, if not, which states and the reason it is not.	[redacted]

[redacted]

If Respondent is a partnership, the names of all general and limited partners. If Respondent is a limited liability company, the names of all direct owners.	[redacted]
Description of Respondent and all affiliated entities and joint ventures transacting business in the energy sector.	

2. Financial Information

Please provide the following for Respondent and/or Parent/Guarantor (as appropriate)	Respondent	Parent/Guarantor

REDACTED

[redacted]

Current debt ratings, including names of rating agencies and dates of ratings. If entity is not rated, please indicate.	[redacted]
Date last fiscal year ended.	
Total revenue for the most recent fiscal year.	
Total net income for the most recent fiscal year.	
Total assets as of the close of the previous fiscal year.	
DUNS Number and Federal Tax ID.	

REDACTED

[redacted]

Please provide a copy of the most recent financials including balance sheet, income statement and cash flow statement.	[redacted]

3. Defaults and Adverse Situations

Describe, in detail, any situation in which Respondent (either alone or as part of a joint venture), or an affiliate of Respondent, defaulted or was deemed to be in noncompliance of its contractual obligations to deliver energy and/or capacity at wholesale within the past five years. Explain the situation, its outcome and all other relevant facts associated with the event described. Identify the name, title and telephone number of the principal manager of the customer/client who asserted the event of default or noncompliance.	[redacted]
Has Respondent, or any affiliate of Respondent, in the last five years, (a) consented to the appointment of, or was taken in possession by, a receiver, trustee, custodian or liquidator of a substantial part of its assets, (b) filed a bankruptcy petition in any bankruptcy court proceeding, (c) answered, consented or sought relief under any bankruptcy or similar law or failed to obtain a dismissal of an involuntary petition, (d) admitted in writing of its inability to pay its debts when due, (e) made a general assignment for the benefit of creditors, (f) was the subject of an involuntary proceeding seeking to adjudicate that Party bankrupt or insolvent, (g) sought reorganization, arrangement, adjustment, or composition of it or its debt under any law relating to bankruptcy, insolvency or reorganization or relief of debtors.	

[redacted]

Describe any facts presently known to Respondent that might adversely affect its ability to provide the service(s) bid herein as provided for in the Request for Proposals.	[redacted]

4. NEPOOL and Power Supply Experience

Is Respondent a member of NEPOOL?	[redacted]
Please list Respondent's NEPOOL Participant ID.	
If Respondent is NOT a NEPOOL member, list the name and Participant ID of the NEPOOL member who will carry Respondent's obligations in its settlement account. Please provide a supporting statement and contact information from such member.	
Please describe Respondent's experience and record of performance in the areas of power marketing, brokering, sales, and/or contracting, for the last five years within NEPOOL and/or the New England region.	
Has Respondent previously provided Default Service to UES? If response is "NO", please provide references as requested below. --- Please provide three references (name, title and contact information) who have contracted with the Respondent for load-following services or who can attest to Respondent's ability in the areas of power supply portfolio management within the past 2 years.	

REDACTED

[redacted]

5. Non Price Terms

Does Respondent extend sufficient financial credit to UES to facilitate the transactions sought via this RFP?	[redacted]
Please indicate what, if any, financial security requirements Respondent has of UES in order to secure the extension of credit. Please attach any proposed contractual language.	
Does Respondent agree that the obligations of both parties are subject to and conditioned upon the NHPUC's approval of the retail rates derived from the transaction sought in this solicitation?	
Please list all regulatory approvals required before service can commence.	
Is Respondent willing to enter into contractual terms substantially as proposed in the Power Supply Agreement contained in Appendix B?	
Provide any proposed modifications to the Power Supply Agreement provided in Appendix B or to the PSA Amendment in Appendix B1. Please briefly list issues here and provide proposed language changes in the document using the "track changes" feature of Microsoft Word, or other reviewable revision marking process.	

Tab A(7). RFP Contact List

The seventh item attached to this Comparison of Bids contains the contact list used by UES during the RFP process. The contact list includes one contact from each entity, a summary of UES's communications with each supplier and UES's expectations with regard to each supplier's intention to bid prior to receipt of indicative bids. Contacts are identified as suppliers, brokers, other LDCs or consultants.

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
RFP Contacts List

Contact Types	Communication	Expectations
[redacted]		

Party	No.	Contact Name	Company	Contact Type	Communic.	Initital Expectation
[redacted]						

Tab A(8). Redlined Power Supply Agreements

The eighth item attached to this Comparison of Bids contains the redline version of the Amendments with Constellation and Nextera.

AMENDMENT No. [redacted]

OF

POWER SALES AGREEMENT

This Amendment No. [redacted] ("Amendment No. [redacted]"), dated and effective as of **June 5, 2024** (the "Effective Date"), amends the Power Sales Agreement, dated [redacted] (the "Agreement") between UNITIL ENERGY SYSTEMS, INC. ("Buyer") and NEXTERA ENERGY MARKETING, LLC~~[COMPANY NAME]~~ ("Seller") (collectively, the "Parties").

Notwithstanding Article 21(d) of the Agreement or anything else to the contrary in either this Amendment No. [redacted] or the Agreement, the Parties' obligations under this Amendment No. [redacted] are subject to Buyer obtaining approval from the NHPUC of the inclusion in retail rates of the amounts payable by Buyer to Seller under this Amendment No. [redacted], without material modification to the obligations of either Party under this Amendment No. [redacted]. Buyer shall use its best efforts to obtain prompt approval of such rates. If Buyer is unable to obtain NHPUC approval by **June 14, 2024**, Buyer and Seller agree to review the status of such approval process and determine whether to continue to pursue the transaction contemplated in this Amendment No. [redacted]. If the Parties cannot agree as to how to continue such transaction, this Amendment No. [redacted] shall terminate and be null and void without liability to either Party.

Buyer shall bear the cost of the NHPUC filing described above except for any costs associated with Seller's intervention. Buyer shall request that the NHPUC give confidential treatment to the terms of this Amendment No [redacted] which is the result of a competitive solicitation held by Buyer.

The Parties hereby agree to further amend the Agreement as follows:

1. Appendix A is amended as attached hereto. The amendment adds a new section reflecting the results of the RFP issued by Buyer on May 7, 2024.

2. Appendix B is amended as attached hereto. The amendment adds pricing associated with the results of the RFP issued by Buyer on -May 7, 2024.

3. Appendix B indicates that the prices listed for the Large Customer Group are Fixed Monthly Adders, therefore the Contract Rate will be calculated as the sum of the Average Weighted RT LMP and the Fixed Monthly Adder as shown in Equation 1. The Average Weighted RT LMP is calculated in accordance with Equation 2.

Equation 1

$$Contract\ Rate = Average\ Weighted\ RT\ LMP + Fixed\ Monthly\ Adder$$

The Average Weighted RT LMP shall be calculated using the MWH of Delivered Energy reported for the Large Customer Group default service load asset, Load

Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight

Asset number 10019, and the hourly real time locational marginal prices ("RT LMP") for the settlement location of Load Asset 10019, which is currently the New Hampshire Load Zone (4002). The Average Weighted RT LMP equals the sum of the products of the RT LMP and the Delivered Energy (MWH) of Load Asset 10019 in each hour of the month of service, divided by the sum of Delivered Energy (MWH) of Load Asset 10019 for the month of service, as shown in Equation 2.

Equation 2

$$Average\ Weighted\ RT\ LMP = \frac{Sum\ [hourly\ RT\ LMP * hourly\ Delivered\ Energy\ (MWH)\ of\ Load\ Asset\ 10}{Sum\ [hourly\ Delivered\ Energy\ (MWH)\ of\ Load\ Asset\ 10019]}$$

The Large Customer Group prices listed in Appendix B are Fixed Monthly Adders requiring the Contract Rate to be calculated as described in Equation 1 and Equation 2, and the Contract Rate will be determined and affirmed by both Buyer and Seller by the third business day following the month of service. Once agreed upon, the Contract Rate for the month of service shall be final and shall not be subject to change in the event that either the New Hampshire RT LMP or the Delivered Energy (MWH) of Load Asset 10019 are subsequently revised or restated.

Formatted: Highlight

Formatted: Highlight

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute and deliver this Amendment No. [redacted] to the Agreement effective as of the Effective Date.

Formatted: Highlight

Unitil Energy Systems, Inc.

BY: ______________________________________

Joseph Conneely
Vice President

NextEra Energy Marketing, LLC~~[Seller]~~

BY: ______________________________________

Its______________________________

Formatted: Highlight

Formatted: Highlight

APPENDIX A

Service Requirements Matrix
By Service Requirement, Load Asset Name and ID, Load Responsibility,
and Applicable Period

For service pursuant to Buyer's RFP issued on **October 31, 2023**

Service Requirement	Load Asset Name and ID	Load Responsibility	Schedule 1	Schedule 2
UES Large Customer Group	UES Large Default Load, 10019	100%	February 1, 2024	July 31, 2024

Formatted: Indent: Left: 0.06"

Formatted: Indent: Left: 0.06"

~~[List All Active Transactions]~~

Formatted: Indent: Left: 0.06"

For service pursuant to Buyer's RFP issued on **May 7, 2024**

Service Requirement	Load Asset Name and ID	Load Responsibility	Schedule 1	Schedule 2
~~UES Small Default Load~~	~~Small Customer Group, 11451~~	~~90%~~	~~August 1, 2024~~	~~January 31, 2025~~
~~UES Medium Default Load~~	~~Medium Customer Group, 11452~~	~~90%~~	~~August 1, 2024~~	~~January 31, 2025~~
UES Large Customer Group	UES Large Default Load, 10019	100%	August 1, 2024	January 31, 2025

Formatted: Highlight

Formatted: Highlight

Formatted: Highlight

Formatted: Highlight

APPENDIX B
Monthly Contract Rate by Service Requirement
Dollars per MWh

For service pursuant to Buyer's RFP issued on **October 31, 2023**

The following are Fixed Monthly Adders. *Please refer to Section 5.1 for calculation of Contract Rate*						
Service Requirement	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24
100% UES Large Customer Group (6 months)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

~~[List All Active Transactions]~~

For service pursuant to Buyer's RFP issued on **May 7, 2024**

~~Service Requirement~~	~~Aug-24~~	~~Sep-24~~	~~Oct-24~~	~~Nov-24~~	~~Dec-24~~	~~Jan-25~~
~~90% UES Small Customer Group (6 months)~~						

~~Service Requirement~~	~~Aug-24~~	~~Sep-24~~	~~Oct-24~~	~~Nov-24~~	~~Dec-24~~	~~Jan-25~~
~~90% UES Medium Customer Group (6 months)~~						

The following are Fixed Monthly Adders. *Please refer to Section 5.1 for calculation of Contract Rate*						
Service Requirement	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25

Formatted: Centered
Formatted: Centered
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Heading 5, Left
Formatted: Font: Bold
Formatted: Highlight
Formatted: Highlight

100% UES Large Customer Group (6 months)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Formatted: Highlight

Formatted: Highlight

Formatted: Highlight

AMENDMENT No. [redacted]

OF

POWER SALES AGREEMENT

Formatted: Highlight

This Amendment No. [redacted]] ("Amendment No. [redacted]"), dated and effective as of **June 5, 2024** (the "Effective Date"), amends the Power Sales Agreement, dated [~~DATE~~[redacted] (the "Agreement") between UNITIL ENERGY SYSTEMS, INC. ("Buyer") and [~~COMPANY NAME~~Constellation Energy Generation, LLC] ("Seller") (collectively, the "Parties").

Formatted: Font color: Red
Formatted: Highlight
Formatted: Font color: Red, Highlight
Formatted: Highlight
Formatted: Highlight

Notwithstanding Article 21(d) of the Agreement or anything else to the contrary in either this Amendment No. [[redacted]] or the Agreement, the Parties' obligations under this Amendment No. [[redacted] are subject to Buyer obtaining approval from the NHPUC of the inclusion in retail rates of the amounts payable by Buyer to Seller under this Amendment No. [redacted]], without material modification to the obligations of either Party under this Amendment No. [redacted]]. Buyer shall use its best efforts to obtain prompt approval of such rates. If Buyer is unable to obtain NHPUC approval by **June 14, 2024**, Buyer and Seller agree to review the status of such approval process and determine whether to continue to pursue the transaction contemplated in this Amendment No. [[redacted]]. If the Parties cannot agree as to how to continue such transaction, this Amendment No. [redacted] shall terminate and be null and void without liability to either Party.

Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight

Buyer shall bear the cost of the NHPUC filing described above except for any costs associated with Seller's intervention. Buyer shall request that the NHPUC give confidential treatment to the terms of this Amendment No. [[redacted]], which is the result of a competitive solicitation held by Buyer.

Formatted: Highlight

The Parties hereby agree to further amend the Agreement as follows:

1. Appendix A is amended as attached hereto. The amendment adds a new section reflecting the results of the RFP issued by Buyer on May 7, 2024.

2. Appendix B is amended as attached hereto. The amendment adds pricing associated with the results of the RFP issued by Buyer on May 7, 2024.

3. Appendix B indicates that the prices listed for the Large Customer Group are Fixed Monthly Adders, therefore the Contract Rate will be calculated as the sum of the Average Weighted RT LMP and the Fixed Monthly Adder as shown in Equation 1. The Average Weighted RT LMP is calculated in accordance with Equation 2.

Equation 1

$$Contract\ Rate = Average\ Weighted\ RT\ LMP + Fixed\ Monthly\ Adder$$

The Average Weighted RT LMP shall be calculated using the MWH of Delivered Energy reported for the Large Customer Group default service load asset, Load

Formatted: Highlight
Formatted: Highlight

Asset number 10019, and the hourly real time locational marginal prices ("RT LMP") for the settlement location of Load Asset 10019, which is currently the New Hampshire Load Zone (4002). The Average Weighted RT LMP equals the sum of the products of the RT LMP and the Delivered Energy (MWH) of Load Asset 10019 in each hour of the month of service, divided by the sum of Delivered Energy (MWH) of Load Asset 10019 for the month of service, as shown in Equation 2.

Equation 2

$$Average\ Weighted\ RT\ LMP = \frac{Sum\ [hourly\ RT\ LMP\ *\ hourly\ Delivered\ Energy\ (MWH)\ of\ Load\ Asset\ 10}{Sum\ [hourly\ Delivered\ Energy\ (MWH)\ of\ Load\ Asset\ 10019]}$$

The Large Customer Group prices listed in Appendix B are Fixed Monthly Adders requiring the Contract Rate to be calculated as described in Equation 1 and Equation 2, and the Contract Rate will be determined and affirmed by both Buyer and Seller by the third business day following the month of service. Once agreed upon, the Contract Rate for the month of service shall be final and shall not be subject to change in the event that either the New Hampshire RT LMP or the Delivered Energy (MWH) of Load Asset 10019 are subsequently revised or restated.

Formatted: Highlight

Formatted: Highlight

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute and deliver this Amendment No. [redacted] to the Agreement effective as of the Effective Date.

Formatted: Highlight

Unitil Energy Systems, Inc.

BY: ____

Joseph Conneely

Vice President

[Seller]

BY: Constellation Energy Generation, LLC ________________________________

Its______________________________

Formatted: Highlight

Formatted: Highlight

APPENDIX A

Service Requirements Matrix
By Service Requirement, Load Asset Name and ID, Load Responsibility,
and Applicable Period

[List All Active Transactions]

For service pursuant to Buyer's RFP issued on **May 7, 2024**

Service Requirement	Load Asset Name and ID	Load Responsibility	Schedule 1	Schedule 2
UES Small Default Load	Small Customer Group, 11451	90%	August 1, 2024	January 31, 2025
UES Medium Default Load	Medium Customer Group, 11452	90%	August 1, 2024	January 31, 2025
UES Large Customer Group	UES Large Default Load, 10019	100%	August 1, 2024	January 31, 2025

Formatted: Highlight
Formatted: Highlight

APPENDIX B
Monthly Contract Rate by Service Requirement
Dollars per MWh

For service pursuant to Buyer's RFP issued on ~~October 31, 2023~~ May 7th, 2024

Formatted: Superscript

[List All Active Transactions]

Service Requirement	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25
90% UES Small Customer Group (6 months)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Formatted: Highlight

Service Requirement	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25
90% UES Medium Customer Group (6 months)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Formatted: Highlight

The following are Fixed Monthly Adders. Please refer to Section 5.1 for calculation of Contract Rate						
Service Requirement	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25
100% UES Large Customer Group (6 months)						

Formatted: Highlight

Formatted: Highlight

Amendment No. [redacted]], dated June 5, 2024
to Power Sales Agreement dated [[redacted]
Page 5 of 5

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
Historical Bidder Participation

Procurement	
Spring 2016	[redacted]
Fall 2016	
Spring 2017	
Fall 2017	
Spring 2018	
Fall 2018	
Spring 2019	
Fall 2019	
Spring 2020	
Fall 2020	
Spring 2021	
Fall 2021	
Spring 2022	
Fall 2022	
Spring 2023	
Fall 2023	
Spring 2024	

[redacted]

Unitil Energy Systems, Inc. ("UES")

Default Service
Request for Proposals

UES Service Requirements

August 1, 2024 – January 31, 2025
Small and Medium Customers (90%)
Large Customers (100%)

Issue Date: May 7, 2024

Unitil Energy Systems, Inc. ("UES")

Default Service
Request for Proposals
Table of Contents

Request for Proposals
To Provide
Default Service Supply
To All Customers of Unitil Energy Systems, Inc

I. Introduction

Unitil Energy Systems, Inc. ("UES") is a local electric distribution company located in New Hampshire. New Hampshire Legislation, RSA 374-F et seq., and the Settlement Agreement for Restructuring the Unitil Companies[1] ("Settlement Agreement") provided retail access for all of UES' retail customers beginning on May 1, 2003.

On September 9, 2005, the NHPUC approved UES' plan for procurement of default service supply, including the solicitation process, for the period beginning May 1, 2006[2]. Subsequently, on July 31, 2012, the NHPUC approved modifications to the timing and structure of UES' default service procurement plan, for the period beginning November 1, 2012[3]. On March 15, 2024, the NHPUC approved UES' plan to procure 90% of full requirements service for the Small and Medium customer groups, while keeping the Large group at 100% of requirements. Pursuant to these Orders, UES procures the power supply required to meet its default service obligations for three customer groups comprised of small, medium and large customers through full requirements contracts

Via this request for proposals ("RFP"), UES seeks competing fixed monthly price offers for 90% of the load requirements of its small and medium customer groups for the service period beginning August 1, 2024 and ending on January 31, 2025. UES also seeks variable monthly price offers, as defined herein, for 100% of the load requirements of its large customer group for the service period beginning August1, 2024 and ending on January 31, 2025. Variable monthly prices are comprised of a pass-through of energy costs at the real-time locational marginal price ("LMP") plus fixed monthly adders, which respondents are asked to bid during the RFP process. The fixed adders are intended to cover all non-energy costs, including capacity, ancillary services, and administration charges. Please see the Proposed Pricing portion of Section V for more information.

This RFP provides background information and historical data, details the service requirements and commercial terms, and elaborates on the procedures to be employed by UES to select the winning suppliers. The complete RFP is available as a single ZIP file ("UES_DS_RFP_Package_2024-05.zip"). In addition, the RFP and its appendices, including the submission form, proposed contract, non-disclosure agreement, as well as the pricing bid sheets have been included as separate, editable electronic files. A number of electronic data files have also been included in Microsoft Excel format. The contents

[1] See Docket DE 01-247.
[2] See Docket DE 05-064.
[3] See Docket DE 12-003.

of each file are described in this document. Please contact Jeff Pentz at (603) 773-6473 or at pentzj@unitil.com with any questions regarding these materials.

II. Description of Default Service

UES is soliciting load-following power supply offers to meet the needs of its customers who take service under its default service tariff for the periods listed in the table in the Supply Obligation Period portion of Section IV. Default service is the only utility-provided supply service and will be available to all UES customers not receiving supply service from a competitive supplier at any time for any reason.

For the purpose of default service procurement, the specified customer groups shall consist of the various rate classes listed in the table below. The default service loads associated with these customer groups are modeled in the ISO Settlement System using the load asset numbers listed in the table. Bidding power suppliers ("Respondents") may submit bids to provide service to any or all customer groups for which a contract is sought via this RFP. Bids to supply each customer group will be evaluated and awarded separately.

Load Asset Description	Customer Rate Classes	Load Asset #
UES Small Default Load	D	11451
UES Medium Default Load	G2, OL	11452
UES Large Default Load	G1	10019

The amount of default service to be supplied by the winning bidder(s) will be determined in accordance with the retail load associated with those customers who rely on default service. UES cannot predict the number of customers that will rely on default service, how much load will be represented by these customers, or how long they will continue to take default service. Recently there has been activity regarding municipal aggregation in the UES service territory. The aggregation programs are designed to move customers from Default Service to competitive supply. Some of these programs may receive approval during the term of this RFP. The Towns of Exeter, Canterbury, Pembroke, Stratham, Webster, and Hampton currently have active aggregations. Concord, Plaistow, Hampton Falls, Kensington, Atkinson, Loudon, Boscawen, and Bow all have either been approved by the P.U.C. or are pending approval. UES expressly reserves the right to encourage customers to choose their own supplier from the competitive marketplace instead of taking default service.

Data Provided

To assist respondents in determining the potential load requirements, a variety of data has been provided with this RFP. The provided data includes the following:

Historical Hourly Loads and Capacity Tag Values are provided for the default service loads by customer group and in aggregate for competitive generation service loads. The hourly loads are measured at the PTF level and are provided for the period of January, 2019 through April 2024. The capacity tag values are the daily sum of the capacity tags for all customers assigned to the supply service being reported. Please see the file named "UES_Historic_Hourly_Loads_Cap_Tags_2024-05.xls."

Historic Retail Monthly Sales Report provides monthly sales data from January 2019 through April 2024 have been compiled and provided. The retail sales report documents retail sales and customer counts by customer rate class and supply type: default service or competitive generation. Please see the file named "UES_Retail_Sales_Report_2024-05.xls."

Class Average Load Shapes (8760 hours), as measured at the customer meter level, are available. Please see the file named "UES_Profiles_2024-05.xls."

Distribution System Loss Factor for each rate class is shown in the following table. The distribution loss factors enable one to estimate the retail usage at the customer meter associated with a given quantity of wholesale supply, or to convert the class average load shapes to wholesale values. Please note that the supplies sought via this RFP will be wholesale supplies measured at the PTF level.

Customer Group	Rate Class	Distribution Loss Factor
Small Customers	D (Domestic)	6.468%
Medium Customers	G2 (Regular General)	6.392%
Medium Customers	OL (Outdoor Lighting)	6.468%
Large Customers	G1 (Large General)	4.591%

Evaluation Loads that UES will use to calculate weighted average prices of bids received from respondents for the purpose of comparing competing bids on the basis of price are provided. These estimated loads may be instructive to respondents, but should in no way be construed to represent any contract quantity or billing determinant or to create any obligation to any party. Evaluation Loads are included on the bid sheets. Please see the file named "UES_Bid_Form_2024-05.xls."

III. General Provisions

Terms and Conditions

For the small and medium customer group default service loads that respondents choose to bid, respondents must offer fixed monthly prices, and for the large customer default service load respondents must offer variable prices in the form of fixed monthly adders to the NH load zone RT LMP for the entire supply periods listed in the table in the Supply Obligation Period portion of Section IV, and shown on the bid sheets. Pricing requirements are further detailed in the Proposed Pricing portion of Section V.

Power Supply Contract

Along with this RFP, UES has provided a proposed Power Sales Agreement ("PSA") which details the contractual terms and conditions under which default service as sought herein will be provided. Respondents who have not previously signed a PSA, or who do not wish to amend a prior PSA, must execute the PSA in Appendix B ("App_B_UES_Power_Sales_Agreement_2024-05.doc").

Respondents who have previously executed a PSA with UES for the provision of Default Service supply may amend their existing PSA with UES in order to implement the proposed transaction. UES has provided a proposed PSA Amendment in Appendix B1 ("App_B1_UES_PSA_Amendment_2024-05.doc").

Bidders may propose contract language modifications. UES will consider proposed contract language modifications to the extent the language clarifies each party's obligations associated with the transactions sought under this solicitation process, and to the extent that any modified contract represents the best non-price terms each party is willing to offer UES.

The obligations of UES and the winning bidder(s) are subject to and conditioned upon NHPUC approval of the solicitation results and the inclusion in retail rates of the costs derived from the transactions sought in this solicitation. UES will use its best efforts to obtain NHPUC's approval, which is expected five (5) business days after filing. Please see schedule below. Winning suppliers should expect their identity to be announced by the NHPUC in its order on the results of the RFP.

Proposal Process and Submission Dates

The following table outlines key dates associated with this procurement process. All times are in Eastern Prevailing Time (EPT).

Process Step	Date
Issue Default Service RFP	Tuesday, May 7, 2024
Non-Disclosure Agreement Due	Tuesday, May 21, 2024
Proposal Forms & Indicative Pricing Due (including proposed contract changes)	Tuesday, May 21, 2024

Final Pricing Due	Tuesday, June 4, 2024, 10:00 a.m.
Winning Supplier Notified	Tuesday, June 4, 2024, 1:00 p.m.
Contracts Executed	Thursday, June 6, 2024
File for Approval of Rates	Friday, June 7, 2024
Anticipated Approval of Rates	Friday, August 14, 2024
UES DS Commences	Thursday, August 1, 2024

Respondents to this RFP for Default Service must submit a completed Proposal Submission Form, including any proposed contract modifications, a non-disclosure agreement, indicative pricing and then final pricing according to the schedule shown above.

All submissions should be marked "UES Default Service RFP" and sent via e-mail to Jeff Pentz at pentzj@unitil.com, Robby Page at pager@unitil.com and to energy_contracts@unitil.com.

Please direct any questions to Jeff Pentz and Robby Page.

Non-Disclosure Agreement ("NDA") must be completed in order for UES to provide its financial information to bidders as well as to protect the confidentiality of bid information. Respondents who have previously signed an NDA with UES for the provision of Default Service supply do not need to execute a new NDA. Respondents who have not previously signed an NDA with UES must execute the NDA in Appendix C ("App_C_UES_NDA_2024_05.doc"). A partially executed NDA or redline version with proposed changes is due by **3:00 p.m. on May 21, 2024**.

Proposal Submission Form must be completed and is attached as Appendix A. Please see the file named "App_A_UES_Submission_Form_2023-10.doc." Submission Forms are due on **May 21, 2024**.

Indicative Pricing is due along with the Proposal Submission Form. Indicative pricing should be submitted on the "Indicative" sheet of the Bid Form ("UES_Bid_Form_2024-05.xls"). Pricing must meet the requirements described in the Proposed Pricing portion of Section V. Indicative pricing is due by **5:00 p.m. EPT on May 21. 2024.**

Proposed contract modifications, on either the full Power Supply Agreement or on the PSA Amendment, are also due along with the Proposal Submission Form on **May 21, 2024**. If respondents propose any changes to the Power Supply Agreement or the Amendment, respondents must provide an electronic copy of the Power Supply Agreement or the Amendment that is marked to show proposed language in a reviewable format. UES will consider the contractual terms and conditions accepted by each bidder as part of its evaluation criteria, as described in Section VI. When final bid prices are received and confirmed, UES intends to conduct its evaluation and select winning bidder(s) within a few hours. For these reasons, it is to each bidder's advantage to resolve contractual issues prior to final bidding.

Final Pricing should be submitted on the "Final" sheet of the Bid Form ("UES_Bid_Form_2024-05.xls"). Respondent's name must be clearly marked. Final pricing is due by **10:00 a.m. EPT on June 4, 2024**.

Winner Notified. UES intends to confirm final pricing, evaluate competing bids as described in Section VI, Evaluation Criteria, and select and notify the winning bidder(s) by **1:00 p.m. EPT on June 4, 2024**. Other bidders will be notified they were not selected by close of business.

UES, at its sole discretion, reserves the right to issue additional instructions or requests for additional information, to extend the due date, to modify any provision in this RFP or any appendix hereto or to withdraw this RFP.

Contact Person and Questions

Questions regarding this RFP should be submitted to Jeff Pentz and Robby Page.

Right to Select Supplier

UES shall have the exclusive right to select or reject any and/or all of the proposals submitted at any time, for any reason and to disregard any submission not prepared according to the requirements contained in this RFP.

Customer Billing and Customer Service

The default service power supplies procured under this RFP will be wholesale supplies. As such, the winning supplier will have no retail customer contact in any form. All customers taking default service will be retail customers of UES. As the retail provider of such service, UES will provide billing and customer service to customers receiving default service. In addition, UES will assume responsibility for the ultimate collection of moneys owed by customers in accordance with rules and regulations approved by the NHPUC.

IV. Service Features

Supply Obligation Period

The supply obligation period for each supply contract will commence at 0001 hours on the dates listed under "Period Begins" in the following table and will terminate at 2400 hours on the dates listed under "Period Ends" in the following table.

Customer Group	Requirements	Period Begins	Period Ends
UES Small Default Load	90%	August 1, 2024	January 31, 2025
UES Medium Default Load	90%	August 1, 2024	January 31, 2025
UES Large Default Load	100%	August 1, 2024	January 31, 2025

Delivery Point

Supplier(s) will be responsible for all settlement obligations associated with the load assets. UES load assets are currently settled at the New Hampshire Load Zone (4002). In the event that NEPOOL implements nodal settlement of load obligations, supplier(s) will be responsible for all settlement obligations at the node where the load assets are settled. The UES load physically exists and is metered at the substations listed in Appendix C of the Power Supply Agreement. The delivery points are at the PTF level.

Form of Service

The winning bidder(s) ("Seller") shall provide firm, load-following power for delivery to ultimate customers taking service under UES' default service tariff, as amended from time to time. The obligations and responsibilities associated with providing default service shall be transferred to the Seller via an Ownership Share for Load Asset, utilizing the NEPOOL Asset Registration Process for load assets 11451 (Small Customer Group), 11452 (Medium Customer Group) and 10019 (Large Customer Group). The percentage Ownership Share for each load asset shall be as listed on the table above under Supply Obligation Period under the column heading "Requirements." The quantity of service that the Seller will be responsible to deliver, and that UES will be responsible to purchase, will be the volumes measured at the delivery points.

Seller shall be responsible for providing and paying for all energy and capacity services and for all ancillary services associated with the Day-Ahead Load Obligation and the Real-Time Load Obligation (as defined in Market Rule 1, Section III of ISO New England Inc.'s Transmission, Markets and Services Tariff (the "ISO Tariff")), associated with the load assets, as required by the ISO Tariff as may be amended or superseded from time to time. UES shall be responsible for providing and paying for the transmission of the power across NEPOOL PTF and for all ancillary services associated with the Regional Network Load (as defined in the Open Access Transmission Tariff, Section III of the ISO Tariff), associated with the load assets. The specific requirements regarding the provision of energy, capacity and ancillary services by the Seller, and regarding the provision of transmission service by UES, are detailed in Article 4 of the proposed Power Supply Agreement, attached as Appendix B.

UES will report the hourly default service load associated with the load assets to ISO-NE on a daily basis in accordance with the reporting practices in New England. The reported loads will incorporate appropriate load allocation and estimation techniques and available meter readings for customers receiving default service from UES. Month end adjustments, based on customer meter readings, will be made to loads approximately 45 days after each month. Such adjustments will be priced at the contract price in effect for the month the load was served.

Renewable Portfolio Standards

In 2007 the State of New Hampshire enacted an Electric Renewable Portfolio Standards law ("NH-RPS Law") (RSA 362-F) to foster the development of renewable energy sources to meet New Hampshire's energy needs. The Supplier(s) of Load Following Service are not required to provide UES' renewable energy obligations resulting from the NH-RPS Law. These requirements will be managed separately by UES

V. Proposal Requirements

Requested Information

Respondents to this RFP must provide the information identified in the Proposal Submission Form attached as Appendix A. Please see the file named "App_A_UES_Submission_Form_2024-05.doc." Respondents are asked to complete the submission form and return it to Jeff Pentz and Robby Page as indicated in Section III. Proposals should contain explanatory, descriptive and/or supporting materials as necessary.

Respondents will find that UES requests on the Proposal Submission Form that bidders indicate whether they will extend sufficient financial credit to UES in order to facilitate the transactions sought. UES will provide a copy of its most recent financials upon completion of the Mutual Confidential Non-Disclosure Agreement attached as Appendix C. UES has proposed financial security terms in the Power Supply Agreement. Respondents are asked to indicate their acceptance of the proposed financial security terms, along with any contract language modifications they propose. Proposed contract language modifications must be provided in a reviewable and editable manner, such as is obtained using the "track changes" features of Microsoft Word. Respondents are also asked to indicate whether they agree that the Power Supply Agreement is subject to NHPUC approval of supporting retail rates as sought by UES.

UES will treat all information received from respondents in a confidential manner and will not, except as required by law or regulatory authority, disclose such information to any third party or use such information for any purpose other than to evaluate the respondent's ability to provide the services sought in this RFP. Respondents bidding to serve UES default service loads should expect that the identity of the winning bidder(s) will be announced by the NHPUC in its order on the results of the RFP.

Proposed Pricing

For the Small and Medium Customer Groups, UES seeks fixed monthly price offers for the six-month period. Respondents must specify the prices, in $/MWh, at which they will provide default service for each month of the supply obligation period associated with the default service loads they choose to bid. Proposed prices may vary by calendar month, but must be uniform for the entire calendar month and must cover the entire supply obligation period sought. Purchases will be made on an "as-delivered" energy basis with prices stated on a fixed $/MWh basis for all MWh reported to the ISO for the load assets. No maximum price is specified; however the resulting retail rates are subject to the review and acceptance of the NHPUC.

For the Large Customer Group, UES seeks variable monthly price offers for the six-month period. Respondents must specify the monthly fixed adders, in $/MWh, at which, in addition to the load-weighted average real-time NH LMP, they will provide default service to the Large Customer Group. Proposed monthly adder prices may vary by calendar month, but must be uniform for the entire calendar month and must cover the entire supply obligation period sought. Purchases will be made on an "as-delivered" energy basis with the monthly contract price equaling the sum of the load-weighted average real-time NH LMP plus the monthly fixed adder as bid during the RFP process. UES and the supplier will be required to confirm the calculation of the final contract price as soon as practical following the month of service in order to facilitate billing under the contract. The final contract price will be stated on a $/MWh basis and will apply to all MWh reported to ISO New England for Load Asset 10019 (Large Customer Group). No maximum price is specified; however the resulting retail rates are subject to the review and acceptance of the NHPUC.

Bidder Requirements

In order to secure reliable, low cost default service power for its customers, UES wishes to include all qualified power suppliers in this solicitation.

Bidders must have access to the ISO settlement process for the entire term of the sale, either as a signatory to the Market Participant Service Agreement ("MPSA") or via arrangements with a signatory to the MPSA to utilize their settlement process.

Respondents are encouraged to establish complete contract language, including financial security arrangements, with UES prior to submission of final pricing.

VI. Evaluation Criteria

The principal criteria to be used in evaluating proposals will include, but may not be limited to:

- Lowest evaluated bid price over the supply obligation period;
- Financial and operational viability of the power supplier, including the establishment of mutually acceptable financial security arrangements; and
- Responsiveness to non-price requirements, including the reasonable extension of financial credit to UES, and agreement that the proposed transactions are subject to NHPUC approval of retail rates as sought by UES.
- Each customer load group supply contract sought will be evaluated and awarded separately.

Respondent pricing will be evaluated by weighting the fixed monthly pricing according to the Evaluation Loads provided on the bid sheets (“UES_Bid_Form_2024-05.xls”) and as described at the end of Section II.

Appendix A: Proposal Submission Form

See file named "App_A_UES_Submission_Form_2024-05.doc"

Appendix B: Power Sales Agreement

See file named “App_B_UES_Power_Sales_Agreement_2024-05.doc”

Appendix B1: Power Sales Agreement Amendment

See file named "App_B1_UES_PSA_Amendment_2024-05.doc"

Appendix C: Mutual Confidential Non-Disclosure Agreement

See file named “App_C_UES_NDA_2024-05.doc”

APPENDIX A: PROPOSAL SUBMISSION FORM

1. General Information

Name of Respondent	
Name of Parent or Guarantor (if any)	
Principal contact person < Name < Title < Company < Mailing address < Telephone number (office) < Telephone number (cell) < Fax number < E-mail address	
Secondary contact person (if any) < Name < Title < Company < Mailing address < Telephone number (office) < Telephone number (cell) < Fax number < E-mail address	
Legal form of business organization of Respondent (e.g., sole proprietorship, partnership, limited partnership, joint venture, or corporation)	
State(s) of incorporation, residency or organization Indicate whether Respondent is in good standing in all states in which Respondent is authorized to do business and, if not, which states and the reason it is not.	

If Respondent is a partnership, the names of all general and limited partners. If Respondent is a limited liability company, the names of all direct owners.	
Description of Respondent and all affiliated entities and joint ventures transacting business in the energy sector.	

2. Financial Information

Please provide the following for Respondent and/or Parent/Guarantor (as appropriate)	Respondent	Parent/Guarantor
Current debt ratings, including names of rating agencies and dates of ratings. If entity is not rated, please indicate.		
Date last fiscal year ended.		
Total revenue for the most recent fiscal year.		
Total net income for the most recent fiscal year.		
Total assets as of the close of the previous fiscal year.		
DUNS Number and Federal Tax ID.		
Please provide a copy of the most recent financials including balance sheet, income statement and cash flow statement.		

3. Defaults and Adverse Situations

Describe, in detail, any situation in which Respondent (either alone or as part of a joint venture), or an affiliate of Respondent, defaulted or was deemed to be in noncompliance of its contractual obligations to deliver energy and/or capacity at wholesale within the past five years. Explain the situation, its outcome and all other relevant facts associated with the event described. Identify the name, title and telephone number of the principal manager of the customer/client who asserted the event of default or noncompliance.	
Has Respondent, or any affiliate of Respondent, in the last five years, (a) consented to the appointment of, or was taken in possession by, a receiver, trustee, custodian or liquidator of a substantial part of its assets, (b) filed a bankruptcy petition in any bankruptcy court proceeding, (c) answered, consented or sought relief under any bankruptcy or similar law or failed to obtain a dismissal of an involuntary petition, (d) admitted in writing of its inability to pay its debts when due, (e) made a general assignment for the benefit of creditors, (f) was the subject of an involuntary proceeding seeking to adjudicate that Party bankrupt or insolvent, (g) sought reorganization, arrangement, adjustment, or composition of it or its debt under any law relating to bankruptcy, insolvency or reorganization or relief of debtors.	
Describe any facts presently known to Respondent that might adversely affect its ability to provide the service(s) bid herein as provided for in the Request for Proposals.	

4. NEPOOL and Power Supply Experience

Is Respondent a member of NEPOOL?	YES or NO
Please list Respondent's NEPOOL Participant ID.	
If Respondent is NOT a NEPOOL member, list the name and Participant ID of the NEPOOL member who will carry Respondent's obligations in its settlement account. Please provide a supporting statement and contact information from such member.	
Please describe Respondent's experience and record of performance in the areas of power marketing, brokering, sales, and/or contracting, for the last five years within NEPOOL and/or the New England region.	
Has Respondent previously provided Default Service to UES? If response is "NO", please provide references as requested below. -- Please provide three references (name, title and contact information) who have contracted with the Respondent for load-following services or who can attest to Respondent's ability in the areas of power supply portfolio management within the past 2 years.	YES or NO -- 1. 2. 3.

5. Non Price Terms

Does Respondent extend sufficient financial credit to UES to facilitate the transactions sought via this RFP?	YES or NO
Please indicate what, if any, financial security requirements Respondent has of UES in order to secure the extension of credit. Please attach any proposed contractual language.	
Does Respondent agree that the obligations of both parties are subject to and conditioned upon the NHPUC's approval of the retail rates derived from the transaction sought in this solicitation?	YES or NO
Please list all regulatory approvals required before service can commence.	
Is Respondent willing to enter into contractual terms substantially as proposed in the Power Supply Agreement contained in Appendix B?	YES or NO
Provide any proposed modifications to the Power Supply Agreement provided in Appendix B or to the PSA Amendment in Appendix B1. Please briefly list issues here and provide proposed language changes in the document using the "track changes" feature of Microsoft Word, or other reviewable revision marking process.	

POWER SUPPLY AGREEMENT

This POWER SUPPLY AGREEMENT ("Agreement") is dated as of **June 5, 2024** and is by and between UNITIL ENERGY SYSTEMS, INC. ("UES" or "Buyer"), a New Hampshire corporation, and [Company] ("Seller"), a [what]. This Agreement provides for the sale by Seller of Default Service, as defined herein, to the Buyer. The Buyer and Seller are referred to herein individually as a "Party" and collectively as the "Parties".

ARTICLE 1. BASIC UNDERSTANDINGS

Seller, in response to a Request for Proposals issued on **May 7, 2024** by the Buyer, has been selected to be the supplier of firm, load-following power to meet the Buyer's Service Requirements as defined in the Service Requirements Matrix found in Appendix A. This Agreement sets forth the terms under which Seller will supply, and Buyer will purchase, Default Service during the Delivery Term.

ARTICLE 2. DEFINITIONS

As used in this Agreement, the following terms shall have the meanings specified in this Article. In addition, except as otherwise expressly provided, terms with initial capitalization used in this Agreement and not defined herein shall have the meaning as defined in the ISO Rules.

Affiliate means, with respect to any Party, any person (other than an individual) that, directly or indirectly, controls, or is controlled by such Party. For this purpose, "control" means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

Average Weighted RT LMP (real time locational marginal price) is the value determined each month during the Delivery Term of the Large Customer Group Service Requirement. The Average Weighted RT LMP is added to the Fixed Monthly Adder to calculate the Contract Rate per MWH for the Large Customer Group Service Requirement. The calculation of the Average Weighted RT LMP is detailed in Section 5.1.

Business Day means a 24-hour period ending at 5:00 p.m. EPT, other than Saturday, Sunday and any day which is a legal holiday or a day on which banking institutions in Boston, Massachusetts are authorized by law or other governmental action to close.

Buyer means Unitil Energy Systems, Inc., its successors, assigns, employees, agents and authorized representatives.

Buyer's System means the electrical transmission and distribution system of the Buyer.

Commencement Date means, with respect to a Service Requirement, the period beginning at the start of HE 0100 EPT on the date set forth for such Service Requirement on Schedule 1 of Appendix A.

Commission means the Federal Energy Regulatory Commission.

Competitive Supplier Terms means the Terms and Conditions for Competitive Suppliers, which are a part of the Retail Delivery Tariff, as may be amended from time to time.

Conclusion Date means the end of the HE 2400 EPT on the date set forth for the Service Requirement on Schedule 2 of Appendix A.

Contract Rate means the value expressed in \$/MWh as set forth in Appendix B, as applicable to each Service Requirement, during a month in the Delivery Term.

Credit Rating means (i) the lower of the ratings assigned to an entity's unsecured, senior long-term debt obligations (not supported by third party credit enhancements) by S&P and Moody's, (ii) in the event the entity does not have a rating for its senior unsecured long-term debt, the lower of the rating assigned to the entity as an issuer rating by S&P and Moody's, or the rating assigned to the entity as an issuer rating by any other rating agency agreed to by both Parties in each Party's sole and exclusive judgment.

Credit Requirements mean the satisfaction of any and all financial measures and/or Credit Rating status so as to avoid a Downgrade Event, as defined in Section 7.3(a).

Customer Disconnection Date means the date when a Default Service Customer is disconnected from service, as determined by the Buyer in accordance with the Retail Delivery Tariff.

Customer Group means the Small Customer Group or the Large Customer Group, as the case may be.

Customer Initiation Date means the date a retail customer of the Buyer begins taking service pursuant to the Schedule DS of the Buyer's Retail Delivery Tariff, as determined by the Buyer.

Customer Termination Date means the date when a Default Service Customer ceases to take service pursuant to Schedule DS under the Retail Delivery Tariff.

Default Service means the provision of Requirements by Seller at the Delivery Point to the Buyer to meet all needs of Default Service Customers.

Default Service Customer(s) means the retail customer(s) in each Customer Group identified in Appendix A taking service pursuant to Schedule DS of the Retail Delivery Tariff during the applicable Delivery Term.

Delivered Energy means the quantity of energy, expressed in MWh, provided by Seller under the terms of this Agreement. This quantity shall be the sum of energy reported to the ISO by the Buyer for each of the Load Assets identified in Section 6.4, with such quantity determined by the Buyer in accordance with Section 6.3 of this Agreement. Such quantity shall not include any allocation of PTF losses up to and including the Delivery Point (which the ISO may assess to Seller in relation to such energy), but shall include transmission and distribution losses on the Buyer's System from the Delivery Point to the meters of Default Service Customers.

Delivery Point means the PTF location where Requirements are settled under ISO Rules. UES load assets are currently settled at the New Hampshire Load Zone (4002). The UES load physically exists and is metered at the substations listed in Appendix C.

Delivery Term(s) means the applicable period associated with a Service Requirement beginning at the start of HE 0100 EPT in Schedule 1 through and including the end of the HE 2400 EPT in Schedule 2 of Appendix A.

EPT means Eastern Prevailing Time.

Fixed Monthly Adder means the dollar per MWH price specified in Appendix B. The Fixed Monthly Adder is added to the Average Weighted RT LMP each month during the Delivery Term of the Large Customer Group Service Requirement in order to calculate the monthly Contract Rate per MWH for the Large Customer Group Service Requirement.

GAAP means Generally Accepted Accounting Principles promulgated by the Financial Accounting Standards Board at the time of issuance of the financial statements.

Governing Documents means, with respect to any particular entity, (a) if a corporation, the (i) articles of organization, articles of incorporation or certificate of incorporation and (ii) the bylaws; (b) if a general partnership, the partnership agreement and any statement of partnership; (c) if a limited partnership, the limited partnership agreement and the certificate of limited partnership; (d) if a limited liability company, the articles or certificate of organization or formation and operating agreement; (e) if another type of entity, any other charter or similar document adopted or filed in connection with the creation, formation or organization of such entity; (f) all equity holders' agreements, voting agreements, voting trust agreements, joint venture agreements, registration rights agreements or other agreements or documents relating to the organization, management or operation of any entity or relating to the rights, duties and obligations of the equity holders of any entity; and (g) any amendment or supplement to any of the foregoing.

Interest Rate means, for any date, the lesser of (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in The Wall Street Journal under "Money Rates" on such day (or if not published on such day, on the most recent preceding day on which published), plus two percent (2%) and (b) the maximum rate permitted by applicable law.

Investment Grade means (i) if an entity has a Credit Rating from both S&P and Moody's then, a Credit Rating from S&P equal to or better than "BBB-" and a Credit Rating from Moody's equal to or better than "Baa3"; or (ii) if an entity has a Credit Rating from only one of S&P and Moody's, then a Credit Rating from S&P equal to or better than "BBB-" or a Credit Rating from Moody's equal to or better than "Baa3 or (iii) if the Parties have mutually agreed in writing on an additional or alternative rating agency, then a Credit Rating from S&P (if applicable) equal to or better than "BBB-" and/or a Credit Rating from Moody's (if applicable) equal to or better than "Baa3", and with respect to the additional or alternative rating agency, a credit rating equal to or better than that mutually agreed to by the Parties in each Party's sole and exclusive judgment.

ISO means ISO New England Inc., the Independent System Operator / Regional Transmission Organization established in accordance with the NEPOOL Agreement, and any successor.

ISO Rules means all rules adopted by the ISO or NEPOOL, as such rules may be amended, added, superseded and restated from time to time, including the NEPOOL Agreement, ISO New England Inc. Transmission, Markets and Services Tariff FERC Electric Tariff No. 3, the Transmission Operating Agreement, and the Participants Agreement, the ISO Manuals, and the NEPOOL Operating Procedures.

kWh means kilowatt-hour.

Large Customer Group means the retail customers assigned to the following customer rate class: Large General Service Schedule G1.

Material Adverse Effect means, with respect to a Party, any change in or effect on such Party after the date of this Agreement that is materially adverse to the transactions contemplated hereby, excluding any change or effect resulting from (a) changes in the international, national, regional or local wholesale or retail markets for electric power; (b) changes in the international, national, regional or local markets for any fuel; (c) changes in the North American, national, regional or local electric transmission or distribution systems; and (d) any action or inaction by a governmental authority, but in any such case not affecting the Parties or the transactions contemplated hereby in any manner or degree significantly different from others in the industry as a whole.

<u>Medium Customer Group</u> means the retail customers assigned to the following customer rate classes: Regular General Service Schedule G2, and Outdoor Lighting Service Schedule OL.

<u>Moody's</u> means Moody's Investors Service Inc., its successors and assigns.

<u>MWh</u> means Megawatt-hour.

<u>NE-GIS</u> means the NEPOOL Generation Information System, which includes a generation information database and certificate system, operated by ISO, its designee or successor entity, that accounts for generation attributes of electricity consumed within New England.

<u>NE-GIS Certificates</u> means a document produced by the NE-GIS that identifies the relevant generation attributes of each MWh accounted for in the NE-GIS from a generation unit.

<u>NEPOOL</u> means the New England Power Pool, or its successor.

<u>NEPOOL Agreement</u> means the Second Restated New England Power Pool Agreement effective on February 1, 2005, as amended or accepted by the Commission and as may be amended, superseded and/or restated from time to time.

<u>NHPUC</u> means the New Hampshire Public Utilities Commission.

<u>NH Load Zone</u> means the New Hampshire Reliability Region as defined in the ISO Rules.

<u>PTF</u> means facilities categorized as Pool Transmission Facilities under ISO Rules.

<u>Requirements</u> shall be defined in Section 4.2(c).

<u>Retail Delivery Tariff</u> means UES' Tariff for Electric Delivery in the State of New Hampshire.

<u>S&P</u> means Standard & Poor's Rating Group, its successors and assigns.

<u>Service Requirement</u> means a load-following, wholesale power supply requirement, defined by a unique combination of Customer Group, load responsibility and Delivery Term as listed in Appendix A.

<u>Small Customer Group</u> means the retail customers assigned to the following customer rate classes: Domestic Delivery Service Schedule D.

ARTICLE 3. TERM, SERVICE PROVISIONS AND REGISTRATION REQUIREMENTS

Section 3.1 <u>Term</u>

This Agreement shall be effective immediately upon execution by the Parties and shall continue in effect until the Service Requirements listed in Appendix A have been fully performed and final payment made hereunder or this Agreement has been otherwise terminated as provided herein by reason of an uncured Event of Default. As of the expiration of this Agreement or, if earlier, its termination, the Parties shall no longer be bound by the terms and provisions hereof, except (a) to the extent necessary to enforce the rights and obligations of the Parties arising under this Agreement before such expiration or termination and (b) the obligations of the Parties hereunder with respect to audit rights, remedies for default, damages claims, indemnification and defense of claims shall survive the termination or expiration of this Agreement to the full extent necessary for their enforcement and the protection of the Party in whose favor they run, subject to any time limits specifically set forth in this Agreement.

Section 3.2 Commencement of Supply

(a) Beginning as of the Commencement Date applicable to the Customer Group set forth on Appendix A, Seller shall provide Requirements to the Buyer. For purposes of certainty: Seller's obligations on the Commencement Date shall be to provide Requirements for all Default Service Customers taking service as of and including the Commencement Date.

(b) With respect to each person or entity that becomes a Default Service Customer subsequent to the Commencement Date, Seller shall provide Requirements to the Buyer to meet the needs of the Default Service Customer(s) as of and including the Customer Initiation Date for such customer initiating such service during the Delivery Term.

(c) During the Delivery Term that Seller provides Default Service to the Buyer's Large Customer Group, Buyer shall make its best efforts to notify Seller promptly of all Customer Initiation Dates of retail customers in the Large Customer Group. Upon such notice, Buyer shall also provide historic annual (prior billed 12 months) peak kVa and total kWh consumption for such customers.

Section 3.3 Termination and Conclusion of Supply

(a) With respect to each Default Service Customer that terminates Default Service, during the Delivery Term, Seller shall not provide Requirements for such customer as of the Customer Termination Date.

(b) During the Delivery Term that Seller provides Default Service to the Buyer's Large Customer Group, Buyer shall make best efforts to notify Seller promptly of all Customer Termination Dates and Customer Disconnection Dates of retail customers in the Large Customer Group. Upon such notice, Buyer shall also provide historic annual (prior billed 12 months) peak kVa and total kWh consumption for such customers.

(c) Seller's obligation to provide Requirements shall cease at the Conclusion Date.

Section 3.4 Distribution Service Interruptions

Seller acknowledges that interruptions in distribution service occur and may reduce the load served hereunder. Seller further acknowledges and agrees that the Buyer may interrupt distribution service to customers consistent with the Distribution Service Terms and the Competitive Supplier Terms. In no event shall a Party have any liability or obligation to the other Party in respect of any such interruptions in distribution service.

Section 3.5 Release of Customer Information

The Buyer will not issue any customer information to Seller unless Seller has first obtained the necessary authorization in accordance with the provisions of the Competitive Supplier Terms.

Section 3.6 Change in Supply; No Prohibition on Programs

(a) Seller acknowledges and agrees that the number of customers and the Requirements to meet the needs of such customers will fluctuate throughout the Delivery Term and may equal zero. The Buyer shall not be liable to Seller for any losses Seller may incur, lost revenues, and losses that may result from any change in Requirements, number or location of customers taking service, the location of the Delivery Point(s), the composition or components of market products or Requirements, or the market for electricity, or change in the Retail Delivery Tariff. Seller further acknowledges and agrees that there is no limit on the number of Customer Initiation Dates, Customer Termination Dates and Customer Disconnection Dates.

(b) Seller acknowledges and agrees that the Buyer has the right but not the obligation to continue, initiate, support or participate in any programs, promotions, or initiatives designed to or with the effect of encouraging customers to leave Default Service for any reason ("Programs"). Nothing in this Agreement shall be construed to require notice to or approval of Seller in order for the Buyer to take any action in relation to Programs.

(c) Seller acknowledges and agrees that the Buyer and Affiliates of the Buyer will not provide Seller preferential access to or use of the Buyer's System and that Seller's sole and exclusive rights and remedies with regard to access to, use or availability of the Buyer's System, and the Buyer's or Affiliates of the Buyer's obligation to transmit electricity are those rights, remedies and obligations provided under the Retail Delivery Tariff, the ISO Rules, and the Buyer's Open Access Transmission Tariff.

Section 3.7 Disclosure Requirements

In the event that the NHPUC implements a disclosure label requirement, which requires the Buyer to document its power supply attributes, then the Seller shall provide the Buyer information pertaining to power plant emissions, fuel types, labor information and any other information required by the Buyer to comply.

Section 3.8 Regulatory Approvals

Notwithstanding Section 21(d) below, or anything else to the contrary herein, the Parties' obligations under this Agreement are subject to Buyer obtaining approval from NHPUC of the inclusion in retail rates of the amounts payable by Buyer to Seller under this Agreement, without material modification to the obligations of either Party under this Agreement. Buyer shall use its best efforts to obtain prompt approval of such rates. If Buyer is unable to obtain NHPUC approval by **June 14, 2024** Buyer and Seller agree to review the status of such approval process and determine whether to continue to pursue the transaction contemplated in this Agreement. If the Parties cannot agree as to how to continue such transaction, this Agreement shall terminate without liability to either Party.

ARTICLE 4. SALE AND PURCHASE

Section 4.1 Provision Delivery and Receipt

Seller shall provide and deliver to the Delivery Point and the Buyer shall receive at the Delivery Point the percent of the Requirements applicable to each Service Requirement as set forth on Appendix A during the Delivery Term.

Section 4.2 Responsibilities

(a) Buyer shall be responsible for arranging and paying for the transmission of the power across NEPOOL PTF and for any ancillary services, allocated to the Network Load, associated with the Service Requirements. Arranging and paying for transmission across NEPOOL PTF, required of the Buyer, includes, but is not limited to taking Regional Network Service under the ISO New England Inc. Transmission, Markets and Services Tariff ("ISO Tariff"). Arranging and paying for ancillary services, required by the Buyer, includes, but is not limited to any transmission dispatch or power administration services, as may be allocated to Network Load in accordance with ISO Rules. Arranging and paying for transmission from NEPOOL PTF to Buyer's distribution facilities includes, but is not limited to, taking Network Integration Transmission Service under the Service Agreement for Network Integration Transmission Service between Northeast Utilities Service Company and UES.

(b) Seller shall be responsible for all present and future obligations, requirements, and costs associated with the Requirements.

(c) The term "Requirements" means the provision of energy at the Delivery Point as set forth in Section 4.2(e), capacity as set forth in Section 4.2(f) and ancillary services as set forth in Section 4.2(g), in each case associated with the Service Requirements as set forth in Appendix A.

(d) If ISO Rules are modified during the Term of this Agreement, which change the allocation of currently existing charges and obligations from the Load Asset, associated with the Service Requirements to the Network Load, associated with the Buyer's transmission responsibilities, then, if possible, the charges or obligations shall be transferred back to the Seller through the ISO and/or ISO settlement process. If such transfer is not possible, then the Seller shall compensate the Buyer for any additional cost. If ISO Rules are modified during the Term of this Agreement, which change the allocation of currently existing charges and obligations from the Network Load, associated with the Buyer's transmission responsibilities to the Load Asset, associated with the Service Requirements, then, if possible, the charges or obligations shall be transferred back to the Buyer through the ISO and/or ISO settlement process. If such transfer is not possible, then the Buyer shall compensate the Seller for such charges. If ISO Rules are changed after the date of this Agreement, which create new charges or obligations, associated with the Service Requirements, then the Seller shall be responsible for such new charges or obligations. Likewise, if ISO Rules are changed during the Term of this Agreement, which create new charges or obligations, associated with the Network Load, associated with the Buyer's transmission responsibilities, then the Buyer shall be responsible for such charges or obligations.

(e) Provision of energy includes, but is not limited to the following. Seller shall have the Day-Ahead Load Obligation and the Real-Time Load Obligation, associated with the Service Requirements at the Delivery Point. Currently, the Energy Settlement Obligation, associated with the Service Requirements at the Delivery Point, is settled at the New Hampshire Load Zone. In the event that NEPOOL or the ISO implements nodal settlement of load obligations of the Day-Ahead Energy Market and Real-Time Energy Market, the Seller shall continue to be responsible for Day-Ahead and Real-Time Load Obligations at the appropriate settlement location(s), associated with the Service Requirements at the Delivery Point.

(f) Provision of capacity includes, but is not limited to the following. Seller shall have the ICAP Settlement Obligation, associated with the Service Requirements at the Delivery Point. Currently, the ICAP Settlement Obligation, associated with the Service Requirements at the Delivery Point, can be satisfied with any ICAP resource, recognized by the ISO in the NEPOOL control-area or imported into the NEPOOL control-area. In the event that ISO implements a locational capacity requirement, including that which was proposed in the Commission's docket number ER03-563, then the Seller will be responsible for providing ICAP at the location, required to meet the Locational ICAP Settlement Obligation, associated with the Service Requirements at the Delivery Point.

(g) Provision of ancillary services, required of the Seller, includes, but is not limited to Regulation, Operating Reserves, Local Second-Contingency-Protection Resource ("LSCPR") other than LSCPR Operating Reserve charges that are monthly fixed-cost charges paid to Special Constraint Resources pursuant to agreements negotiated pursuant to Schedule 19 of Section II - Open Access Transmission Tariff, Net Commitment Period Compensation ("NCPC") other than LSCPR NCPC charges that are monthly fixed-cost charges paid to Specialty Constraint resources pursuant to agreements negotiated under Schedule 19 of Section II – Open Access Transmission Tariff, Forward Reserves, and any transmission dispatch or power administration services, as may be allocated to the Owner of the Load Assets, associated with the Service Requirements in accordance with ISO Rules. If ISO Rules are changed such that locational ancillary services are required, then the Seller shall be responsible for meeting the locational ancillary services requirement, associated with the Service Requirements at the Delivery Point.

(h) It is the intent of the Parties that for each Financial Transmission Rights Auction ("FTR Auction") conducted by the ISO for months within the Delivery Terms(s), those Auction Revenue Rights ("ARRs") associated solely with the Service Requirement shall be assigned or paid to Seller, provided, however, Buyer shall be under no obligation to participate in any manner in any FTR Auction in order to increase Auction Revenue Right quantities.

ARTICLE 5. AMOUNT, BILLING and PAYMENT

Section 5.1 Amount

The amount payable by the Buyer to Seller for Delivered Energy in a month shall be the product of (a) the sum of the Delivered Energy for each Customer Group, as identified in Appendix A in each month during the applicable Delivery Term; and (b) the Contract Rate for such Service Requirement as identified in Appendix B for such month during the applicable Delivery Term.

Appendix B indicates that the prices listed for the Large Customer Group are Fixed Monthly Adders, therefore the Contract Rate will be calculated as the sum of the Average Weighted RT LMP and the Fixed Monthly Adder as shown in Equation 1. The Average Weighted RT LMP is calculated in accordance with Equation 2.

Equation 1

$$Contract\ Rate = Average\ Weighted\ RT\ LMP + Fixed\ Monthly\ Adder$$

The Average Weighted RT LMP shall be calculated using the MWH of Delivered Energy reported for the Large Customer Group default service load asset, Load Asset number 10019, and the hourly real time locational marginal prices ("RT LMP") for the settlement location of Load Asset 10019, which is currently the New Hampshire Load Zone (4002). The Average Weighted RT LMP equals the sum of the products of the RT LMP and the Delivered Energy (MWH) of Load Asset 10019 in each hour of the month of service, divided by the sum of Delivered Energy (MWH) of Load Asset 10019 for the month of service, as shown in Equation 2.

Equation 2

$$Average\ Weighted\ RT\ LMP = \frac{Sum\ [hourly\ RT\ LMP\ *\ hourly\ Delivered\ Energy\ (MWH)\ of\ Load\ Asset\ 10019]}{Sum\ [hourly\ Delivered\ Energy\ (MWH)\ of\ Load\ Asset\ 10019]}$$

The Large Customer Group prices listed in Appendix B are Fixed Monthly Adders requiring the Contract Rate to be calculated as described in Equation 1 and Equation 2, and the Contract Rate will be determined and affirmed by both Buyer and Seller by the third business day following the month of service. Once agreed upon, the Contract Rate for the month of service shall be final and shall not be subject to change in the event that either the New Hampshire RT LMP or the Delivered Energy (MWH) of Load Asset 10019 are subsequently revised or restated.

Section 5.2 Billing and Payment

(a) On or before the twentieth (20th) day of each month ("Invoice Date") during the term of this Agreement, Seller shall calculate the amount due and payable to Seller pursuant to this Article 5, for Delivered Energy with respect to the preceding month (the "Calculation"). Seller shall provide the Calculation to the Buyer and such Calculation shall include sufficient detail for the Buyer to verify its formulation and computation. Calculations under this paragraph shall be subject to recalculation in accordance with Article 6 and shall be subject to adjustment (positive or negative) based upon such recalculation (a "Reconciliation Adjustment"). Seller shall promptly calculate the Reconciliation Adjustment upon receiving data described in Section 6.3 and shall include the adjustment, if any, in the next month's Invoice. A Reconciliation Adjustment based upon a change in the quantity for an earlier month shall be calculated using the applicable Contract Rate for the month in which the Delivered Energy was received.

(b) Seller shall submit to the Buyer an invoice with such Calculation as provided for in paragraph (a) of this Section (the "Invoice") and the respective amounts due under this Agreement on the Invoice Date. The Buyer shall pay Seller the amount of the Invoice (including the Reconciliation Adjustment, if any, as a debit or credit) less any amounts disputed in accordance with Section 5.3, on or before the later of the last Business Day of each month, or the tenth (10th) day after receipt of the Invoice, or, if such day is not a Business Day, then on the next following Business Day, (the "Due Date"). Except for amounts disputed in accordance with Section 5.3, if all or any part of the Invoice remains unpaid after the Due Date, interest shall accrue after but not including the Due Date and be payable to Seller on such unpaid amount at the Interest Rate in effect on the Due Date. The Due Date for a Reconciliation Adjustment shall be the Due Date of the Invoice in which it is included.

(c) Each Party shall notify the other Party upon becoming aware of an error in an Invoice, Calculation or Reconciliation Adjustment (whether the amount is paid or not) and Seller shall promptly issue a corrected Invoice. Overpayments shall be returned by the receiving Party upon request or deducted by the receiving Party from subsequent invoices, with interest accrued at the Interest Rate from the date of the receipt of the overpayment until the date paid or deducted.

Section 5.3 Challenge to Invoices

Either Party may challenge, in writing, the accuracy of Calculations, Invoices, Reconciliation Adjustments and data no later than twenty-four (24) months after the Due Date of the Invoice in which the disputed information is contained. If a Party does not challenge the accuracy within such twenty-four (24) month period, such Invoice shall be binding upon that Party and shall not be subject to challenge. If any amount in dispute is ultimately determined (under the terms herein) to be due to the other Party, it shall be paid or returned (as the case may be) to the other Party within three (3) Business Days of such determination along with interest accrued at the Interest Rate from the (i) date due and owing in accordance with the Invoice until the date paid or (ii) if the amount was paid and is to be returned, from the date paid, until the date returned.

Section 5.4 Taxes, Fees and Levies

Seller shall be obligated to pay all present and future taxes, fees and levies ("Taxes") which may be assessed by any entity upon the Seller's performance under this Agreement the purchase and sale of Requirements. Seller shall pay all Taxes with respect to the Requirements up to and at the Delivery Point, and the Buyer will pay all Taxes with respect to the Requirements after the Delivery Point. All Requirements, including electricity and other related market products delivered hereunder by Seller to the Buyer shall be sales for resale with the Buyer reselling such electricity and products.

Section 5.5 Netting and Setoff

Except for security provided pursuant to Section 7.3 (which shall not be considered for purposes of this Section 5.5) and unless otherwise specified in another agreement between the Parties, if the Parties are required to pay an amount in the same month each to the other under this Agreement or any other agreement between the Parties, or if any costs that are a Party's responsibility under this Agreement are incorrectly or inappropriately charged to the Party by the ISO, such amounts shall be netted, and the Party owing the greater aggregate amount shall pay to the other Party any difference between the amounts owed. Each Party reserves all rights, setoffs, counterclaims and other remedies and defenses (to the extent not expressly herein or therein waived or denied) that such Party has or to which such Party may be entitled arising from or out of this Agreement or the other agreement. Further, if the Buyer incurs any costs or charges that are the responsibility of Seller under this Agreement, such costs or charges may, at the Buyer's election, be netted against any amount due to Seller under this Agreement. All outstanding obligations to make payment under this Agreement or any other agreement between the Parties may be netted against each other, set off or recouped there from, or otherwise adjusted.

ARTICLE 6. QUALITY; LOSSES and QUANTITIES REQUIRED; DETERMINATION AND REPORTING OF HOURLY LOADS

Section 6.1 Quality

All electricity shall be delivered to the Buyer in the form of three-phase sixty-hertz alternating current at the Delivery Point.

Section 6.2 Losses

Seller shall be responsible for any transmission losses up to and including the Delivery Point. Losses beyond the Delivery Point are included in Delivered Energy and are paid for by the Buyer at the applicable Contract Rate.

Section 6.3 Determination and Reporting of Hourly Loads

The Buyer will estimate the Delivered Energy for Default Service provided by Seller pursuant to this Agreement based upon average load profiles developed for each of the Buyer's customer classes, actual metered data, as available, and the Buyer's actual total hourly load. The Buyer shall report to the ISO and Seller, the estimated Delivered Energy. In accordance with the ISO Rules, the Buyer will normally report to the ISO and to Seller, the Seller's estimated Delivered Energy by 1:00 P.M EPT of the second following Business Day after delivery. The Buyer shall have the right but not the obligation, in its sole and exclusive judgment, to modify the Estimation Process from time to time, provided that any such modification is designed with the objective of improving the accuracy of the Estimation Process.

Each month, the Buyer shall reconcile the Buyer's estimate of the Delivered Energy based upon the Buyer's meter reads (such meter reads as provided for in the Retail Delivery Tariff). The reconciliation, including all losses, shall be the adjusted Delivered Energy. In accordance with the ISO Rules the Buyer will normally notify the ISO of any resulting adjustment (debit or credit) to Seller's account for the Load Assets (set forth in Section 6.4) no later than the last day of the third month following the billing month.

Section 6.4 ISO Settlement Power System Model Implementation

The Default Service provided by Seller pursuant to this Agreement will be initially represented within the ISO Settlement Power System Model as described in Appendix A.

As soon as possible after the execution of this Agreement and before the Commencement Date, the Buyer shall assign to Seller, and Seller shall accept assignment of an Ownership Share for each Load Asset identified in Appendix A. Such assignment shall be effective beginning on the Commencement Date. Seller shall take any and all actions necessary to effectuate such assignment including executing documents required by ISO Rules. Once Seller's provision of Default Service terminates (at the end of a Delivery Term or otherwise), the Buyer and Seller will terminate Seller's Ownership Shares of the aforementioned Load Assets.

The Buyer shall have the right to change the Load Asset designations (identified above) from time to time, consistent with the definition and provision of Default Service. If and to the extent such designations change, the Buyer and Seller shall cooperate to timely put into effect the necessary documents that may be required to implement the new designations and terminate the prior designations.

ARTICLE 7. DEFAULT AND TERMINATION

Section 7.1 Events of Default

(a) Any one or more of the following events shall constitute an "Event of Default" hereunder with respect to the Buyer:

(i) Failure of the Buyer

(A) in any material respect to comply with, observe or perform any covenant, warranty or obligation under this Agreement (but excluding events that are otherwise specifically covered in this Section as a separate Event of Default and except due to causes excused by Force Majeure or attributable to Seller's' in breach of this Agreement); and

(B) After receipt of written notice from Seller such failure continues for a period of five (5) Business Days, or, if such failure cannot be reasonably cured within such five (5) Business Day period, such further period as shall reasonably be required to effect such cure (but in no event longer than thirty (30) days), provided that the Buyer commences within such five (5) Business Day period to effect a cure and at all times thereafter proceed diligently to complete the cure as quickly as possible and provides to Seller written documentation of its efforts and plan to cure and estimated time for completion of the cure.

(ii) Failure of the Buyer to (A) make when due any undisputed payment due to Seller hereunder; and (B) after receipt of written notice from Seller such failure continues for a period of three (3) Business Days.

(iii) Failure of the Buyer to accept Default Service in accordance with Article 3 (unless excused by Force Majeure or attributable to the Seller's breach of this Agreement, or otherwise in accordance with this Agreement).

(b) Any one or more of the following events shall constitute an "Event of Default" hereunder with respect to Seller:

(i) Failure of Seller

(A) in any material respect to comply with, observe, or perform any covenant, warranty or obligation under this Agreement (but excluding events that are otherwise specifically covered in this Section as a separate Event of Default and except due to causes excused by Force Majeure or attributable to the Buyer's in breach of this Agreement); and

(B) after receipt of written notice from the Buyer such failure continues for a period of five (5) Business Days, or, if such failure cannot be reasonably cured within such five (5) Business Day period, such further period as shall reasonably be required to effect a cure (but in no event longer than thirty (30) days), provided that Seller commences within such five (5) Business Day period to effect such cure and at all times thereafter proceeds diligently to complete the cure as quickly as possible and provides to the Buyer written documentation of its efforts and plan to cure and estimated time for completion of the cure;

(ii) Failure of Seller to provide Requirements in accordance with Articles 3 and 4

(c) Any one or more of the following events with respect to either Party shall constitute an "Event of Default" hereunder with respect to such Party:

(i) The entry by a court having jurisdiction in the premises of (A) a decree or order for relief in respect of such Party in an involuntary case or proceeding under any applicable federal or state bankruptcy, insolvency, reorganization or other similar law, or (B) a decree or order adjudging such Party as bankrupt or insolvent, or approving as properly filed a petition seeking reorganization, arrangement, adjustment or composition of or in respect of such Party under any applicable federal or state law, or appointing a custodian, receiver, liquidator, assignee, trustee, sequestrator or other similar official of such Party or of any substantial part of its property, or ordering the winding up or liquidation of its affairs;

(ii) The commencement by such Party of a voluntary case or proceeding, or any filing by a third party of an involuntary case or proceeding against a Party that is not dismissed within forty-five (45) days of such filing, under any applicable federal or state bankruptcy, insolvency, reorganization or other similar law, or of any other case or proceeding to be adjudicated as bankrupt or insolvent, or the consent by it to the entry of a decree or order for relief in respect of such Party in an involuntary case or proceeding under any applicable federal or state bankruptcy, insolvency, reorganization or other similar law or to the commencement of any bankruptcy or insolvency case or proceeding against it, or the filing by it of a petition or answer or consent seeking reorganization or relief under any applicable federal or state law, or the consent by it to the filing of such petition or to the appointment of or taking possession by a custodian, receiver, liquidator, assignee, trustee, sequestrator or other similar official of a Party or of any substantial part of its property, or the making by it of an assignment for the benefit of creditors, or the admission by it in writing of its inability to pay its debts generally as they become due, or the taking of corporate action by such Party in furtherance of any such action;

(iii) Any representation or warranty made by a Party is or becomes false or misleading in any material respect.

(iv) Failure of such Party to deliver Performance Assurance when due in accordance with Section 7.3 if such failure is not remedied within three (3) Business Days after written notice.

Section 7.2 Remedies Upon Default

The Parties shall have the following remedies available to them with respect to the occurrence of an Event of Default with respect to the other Party hereunder:

(a) Upon the occurrence of an Event of Default, the non-defaulting Party shall have the right to (i) continue performance under this Agreement and exercise such rights and remedies as it may have at law, in equity or under this Agreement and seek remedies as may be necessary or desirable to enforce performance and observation of any obligations and covenants under this Agreement, so long as such rights and remedies are not duplicative of any other rights and remedies hereof, and do not otherwise enable the non-defaulting Party to obtain performance or payments in excess of the performance and payments to which it is otherwise entitled pursuant to this Agreement, or (ii) at its option, give such defaulting Party a written notice (a "Termination Notice") terminating this Agreement. Upon a termination for an Event of Default under Section 7.1(a), (b) or (c)(iii) and (iv), such termination shall be effective as of the date specified in the Termination Notice, which date shall be no earlier than the date such notice is effective and no later than thirty (30) days after the date of such notice is provided to the defaulting Party in accordance with Article 8. Upon a termination for an Event of Default under Section 7.1(c)(i) or (ii), such termination shall be effective as of the Event of Default, upon notice being provided to the defaulting Party in accordance with Article 8. Any attempted cure by a defaulting Party after a Termination Notice has been provided or the effective termination under Section 7.1(c)(i) or (ii) shall be void and of no effect. The Parties' obligations under this Agreement, in general and under this Section 7.2 in particular, are subject to the duty to mitigate damages as provided under common law.

(b) At any time after the occurrence of an Event of Default, or the delivery of a Termination Notice to the defaulting Party by the non-defaulting Party, the non-defaulting Party may exercise any rights it may have pursuant to the Section 7.3 (Security).

(c) In the event of termination for an Event of Default as provided in Section 7.1, in addition to any amounts owed for performance (or failure to perform) hereunder prior to such termination, the non-defaulting Party may recover, without duplication, its direct damages resulting from such Event of Default; such damages shall include the positive (if any) present value of this Agreement to the non-defaulting Party for the portion of the Delivery Term remaining at the time of such termination, to be determined by reference to market prices, transaction costs and load reasonably projected for the remaining portion of the Delivery Term ("Termination Damages"). The Termination Damages shall include all reasonably incurred transaction costs and expenses that otherwise would not have been incurred by the non-defaulting Party. In determining its Termination Damages, the non-defaulting Party shall offset its losses and costs by any gains or savings realized by the non-defaulting Party as a result of the termination.

Payment of Termination Damages, if any, shall be made by the defaulting Party to the non-defaulting Party within five (5) days after calculation of such Termination Damages and receipt of a notice including such calculation of the amounts owed hereunder and a written statement showing in reasonable detail the calculation and a summary of the method used to determine such amounts. Upon the reasonable request of the defaulting Party, the non-defaulting Party shall provide reasonable documentation to verify the costs underlying the Termination Damages. If the defaulting Party disputes the non-defaulting Party's calculation of the Termination Damages, in whole or in part, the defaulting Party shall, within five (5) days of receipt of the non-defaulting Party's calculation of the Termination Damages, provide to the non-defaulting Party a detailed written explanation of the basis for such dispute; provided, however, that, the defaulting Party shall first pay the Termination Damages, if any, to the non-defaulting Party in accordance with the preceding sentence, and the non-defaulting Party shall then deposit such disputed amount into an interest bearing escrow account for the benefit of the prevailing Party and the dispute shall be resolved in accordance with Section 15.2.

(d) Notwithstanding any other provision of this Agreement, the cure of any default or failure to comply with, observe or perform any covenant, warranty or obligation under this Agreement within the period provided therefor in this Article shall not release such defaulting Party from its obligations under Section 9.2 of this Agreement.

(e) Upon termination the Buyer shall, and upon the occurrence of an Event of Default by Seller, the Buyer shall have the right to, immediately notify the ISO that (i) the assignment from the Buyer to Seller of the applicable Ownership Share has been terminated, (ii) the Load Assets shall be removed from Seller's account and placed in the account of the Buyer and (iii) Seller consents to such action. In the event the Buyer so notifies the ISO, Seller shall immediately take any and all actions that may be required by the ISO to remove the Load Assets from Seller's account and place them in the account of the Buyer. If the Agreement has not been terminated, the Buyer, in its sole discretion with 5 Business Days prior notice to Seller, may elect to assign the applicable Ownership Share of the Load Assets to the account of Seller and Seller shall accept such assignment, consistent with the actions required by Section 6.4 of this Agreement.

Section 7.3 <u>Security</u>

(a) If the Credit Rating of either Party is downgraded by Moody's and S&P, such that its Credit Rating is below an Investment Grade (a "Downgrade Event"), then within three (3) Business Days after a request of the other Party, the downgraded Party shall deliver the applicable amount of performance assurance required pursuant to this Article 7 ("Performance Assurance") to the other Party ("Compliant Party").

(b) If Performance Assurance is required to be posted by a Party pursuant to the immediately preceding paragraph, the following Sections 7.3(b)(i) through 7.3(b)(iv) shall apply:

(i) The Compliant Party shall calculate its exposure under this Agreement as soon as practicable after the Downgrade Event, and on a monthly basis thereafter ("Performance Assurance Calculation Date").

(ii) All Performance Assurance shall be delivered in the form of: (i) U.S. Dollars delivered by wire transfer of immediately available funds ("Funds"); or (ii) a Letter of Credit from a Qualified Institution (as defined herein). For purposes of determining the amount of Performance Assurance held at any time, a Letter of Credit shall be valued at zero unless it expires more than thirty (30) days after the date of valuation. For purposes of this Agreement, the Parties acknowledge that any Performance Assurance provided by Buyer shall be in the form of Funds as defined in this Section 7.3. For purposes hereof, "Letter(s) of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank (which is not an affiliate of either Party) with such bank having a credit rating of at least A- from S&P and A3 from Moody's, having $1,000,000,000 in assets (a "Qualified Institution"), and otherwise being in a form acceptable to the Party in whose favor the letter of credit is issued. Costs of a Letter of Credit shall be borne by the applicant for such Letter of Credit.

(iii) For purposes hereof, it shall be a Letter of Credit Default ("Letter of Credit Default") with respect to an outstanding Letter of Credit, upon the occurrence of any of the following events: (i) the bank issuing the Letter of Credit shall fail to maintain a credit rating of at least "A-" by S&P and "A3" by Moody's, (ii) the bank issuing the Letter of Credit shall fail to comply with or perform its obligations under such Letter of Credit if such failure shall be continuing after the lapse of any applicable grace period; (iii) the bank issuing the Letter of Credit shall disaffirm, disclaim, repudiate or reject, in whole or in part, or challenge the validity of such Letter of Credit; (iv) such Letter of Credit shall fail or cease to be in full force and effect at any time during the term of any outstanding transaction; or (v) the pledgor or the bank issuing the Letter of Credit shall fail to cause the renewal or replacement of the Letter of Credit to the secured party at least thirty (30) Business Days prior to the expiration of such Letter of Credit; provided, however, that no Letter of Credit Default shall occur in any event with respect to a Letter of Credit after the time such Letter of Credit is required to be canceled or returned to the pledgor in accordance with the terms of this Agreement. If a Letter of Credit Default occurs, then the Party which applied for such Letter of Credit shall have five (5) Business Days to cure the event(s) causing the Letter of Credit Default or to replace the Letter of Credit with a substitute Letter of Credit or Funds. Any failure to cure the event(s) causing the Letter of Credit Default or to provide a substitute Letter of Credit or Funds within five (5) Business Days of the event(s) leading to the Letter of Credit Default shall be an Event of Default under Section 7.1(c)(iv).

(iv) The Compliant Party will be entitled to hold posted Performance Assurance, provided that the following conditions applicable to it are satisfied: (1) the Compliant Party is not a defaulting Party; (2) the Compliant Party has and maintains an Investment Grade Credit Rating required in Section 7.3(a), as applicable; and (3) the posted Performance Assurance is held only in the United States. For funds held as Performance Assurance by the Compliant Party, the Interest Rate will be the Federal Funds Rate as from time to time in effect. “Federal Funds Rate” means, for the relevant determination date, the rate opposite the caption “Federal Funds (Effective)” as set forth in the weekly statistical release designated as H.15 (519), or any successor publication, published by the Board of Governors of the Federal Reserve System. Such interest shall be calculated commencing on the date Performance Assurance in the form of cash is received by a Party but excluding the earlier of: (i) the date Performance Assurance in the form of cash is returned to a Party; or (ii) the date Performance Assurance in the form of cash is applied to a pledgor’s obligations pursuant to Section 7.3 with the net amount of interest accrued monthly being payable on the third Business Day of the following month. A Party holding Performance Assurance may apply such Performance Assurance, without prior notice to the other party, to satisfy the obligations of the other Party in accordance with Section 7.2. Each Party hereby covenants and agrees that it shall be entitled herein to hold posted Performance Assurance as custodian on its own behalf as a secured party if it meets the criteria set forth above in this Section 7.3. However, if the Party holding Performance Assurance is not eligible to hold posted Performance Assurance pursuant to this Section 7.3, then such Party shall be considered ineligible to hold posted Performance Assurance as a secured party and such posted Performance Assurance shall be maintained as follows: the ineligible secured party will cause all posted Performance Assurance received from the other Party to be segregated from the secured party's own property and identified clearly as Performance Assurance and to be held in an account in which no property of the secured party is held (a “Collateral Account”) with a domestic office of a Qualified Institution, each of which accounts may include property of other parties which have delivered posted Performance Assurance to the secured party under other agreements, but will bear a title indicating that the secured party's interest in said account is as a holder of collateral. Such accounts will bear interest at the rate offered by the Qualified Institution. In addition, the secured party may direct the pledgor to transfer or deliver eligible Performance Assurance directly into the secured party's Collateral Account. The secured party shall cause statements concerning the posted Performance Assurance transferred or delivered by the pledgor to be sent to the pledgor on request, which may not be made more frequently than once in each calendar month.

(c) Prior to the Commencement Date and at any time upon the request by Buyer of Seller or by Seller of Buyer, the Party to whom the request is made shall establish that it meets the Credit Requirements by providing (x) a certificate of one of its authorized officers, accompanied by supporting certified financial statements and (y) documentation of its Credit Rating, as applicable. Buyer and Seller shall inform the other Party within one (1) Business Day of any failure to satisfy the Credit Requirements, provided that, in no event, shall the failure of a Party to provide the notice required pursuant to this sentence constitute a default or an Event of Default pursuant to Section 7.1.

Section 7.4 <u>Forward Contract</u>

Each Party represents and warrants to the other that it is a “forward contract merchant” within the meaning of the United States Bankruptcy Code, that this Agreement is a “forward contract” within the meaning of the United States Bankruptcy Code, and that the remedies identified in this Agreement, including those specified in Section 7, shall be “contractual rights” as provided for in 11 U.S.C. § 556 as that provision may be amended from time to time.

ARTICLE 8. NOTICES, REPRESENTATIVES OF THE PARTIES

Section 8.1 Notices

Any notice, demand, or request required or authorized by this Agreement to be given by one Party to another Party shall be in writing. It shall either be sent by facsimile (with receipt confirmed by telephone), courier, personally delivered (including overnight delivery service) or mailed, postage prepaid, to the representative of the other Party designated in accordance with this Article. Any such notice, demand, or request shall be deemed to be given (i) when sent by facsimile confirmed by telephone, (ii) when actually received if delivered by courier or personal delivery (including overnight delivery service) or (iii) seven (7) days after deposit in the United States mail, if sent by first class mail return receipt requested.

Notices and other communications by Seller to the Buyer shall be addressed to:

Mr. Joseph Conneely
Vice President
Unitil Energy Systems, Inc.
6 Liberty Lane West
Hampton, NH 03842
(603) 773-6452 (phone)
(603) 773-6652 (fax)

and

Notices concerning Article 7 shall also be sent to:

Mr. Todd Diggins
Director of Finance
Unitil Energy Systems, Inc.
6 Liberty Lane West
Hampton, NH 03842
(603) 773-6612 (phone)
(603) 773-6812 (fax)

Notices and other communications by the Buyer to Seller shall be addressed to:

[Name]

[Company]

[Address]

[City, State & Zip]

[Phone]

[FAX]

Any Party may change its representative or address for notices by written notice to the other Party; however such notice shall not be effective until it is received by the other Party.

Section 8.2 Authority of Representative

The Parties' representatives shall have full authority to act for their respective Party in all matters relating to the performance of this Agreement. Notwithstanding the foregoing, a Party's representative shall not have the authority to amend, modify, or waive any provision of this Agreement unless they are duly authorized officers of their respective entities and such amendment, modification or waiver is made in accordance to Article 17.

ARTICLE 9. LIABILITY; INDEMNIFICATION; RELATIONSHIP OF PARTIES

Section 9.1 Limitation on Consequential, Incidental and Indirect Damages

EXCEPT AS EXPRESSLY PROVIDED IN THIS AGREEMENT, TO THE FULLEST EXTENT PERMISSIBLE BY LAW, NEITHER THE BUYER NOR SELLER, NOR THEIR RESPECTIVE OFFICERS, DIRECTORS, AGENTS, EMPLOYEES, PARENT OR AFFILIATES, SUCCESSOR OR ASSIGNS, OR THEIR RESPECTIVE OFFICERS, DIRECTORS, AGENTS, OR EMPLOYEES, SUCCESSORS, OR ASSIGNS, SHALL BE LIABLE TO THE OTHER PARTY OR ITS PARENT, SUBSIDIARIES, AFFILIATES, OFFICERS, DIRECTORS, AGENTS, EMPLOYEES, SUCCESSORS OR ASSIGNS, FOR CLAIMS, SUITS, ACTIONS OR CAUSES OF ACTION FOR INCIDENTAL, INDIRECT, SPECIAL, PUNITIVE, MULTIPLE OR CONSEQUENTIAL DAMAGES (INCLUDING ATTORNEY'S FEES OR LITIGATION COSTS EXCEPT AS EXPRESSLY PROVIDED IN 15.2) CONNECTED WITH OR RESULTING FROM PERFORMANCE OR NON-PERFORMANCE OF THIS AGREEMENT, OR ANY ACTIONS UNDERTAKEN IN CONNECTION WITH OR RELATED TO THIS AGREEMENT, INCLUDING ANY SUCH DAMAGES WHICH ARE BASED UPON CAUSES OF ACTION FOR BREACH OF CONTRACT, TORT (INCLUDING NEGLIGENCE AND MISREPRESENTATION), BREACH OF WARRANTY, STRICT LIABILITY, STATUTE, OPERATION OF LAW, OR ANY OTHER THEORY OF RECOVERY. THE PROVISIONS OF THIS SECTION SHALL APPLY REGARDLESS OF FAULT AND SHALL SURVIVE TERMINATION, CANCELLATION, SUSPENSION, COMPLETION OR EXPIRATION OF THIS AGREEMENT.

Section 9.2 Indemnification

(a) Seller agrees to defend, indemnify and save the Buyer, its officers, directors, employees, agents, successors assigns, and Affiliates and their officers, directors, employees and agents harmless from and against any and all third-party claims, suits, actions or causes of action and any resulting losses, damages, charges, costs or expenses, (including reasonable attorneys' fees and court costs), arising from or in connection with any (a) breach of a representation or warranty or failure to perform any covenant or agreement in this Agreement by Seller, (b) any violation of applicable law, regulation or order by Seller, (c) any act or omission by Seller with respect to this Agreement, first arising, occurring or existing during the term of this Agreement, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination of this Agreement, except to the extent caused by an act of gross negligence or willful misconduct by an officer, director, agent, employee, or Affiliate of the Buyer or its respective successors or assigns.

(b) The Buyer agrees to defend, indemnify and save Seller, its officers, directors, employees, agents, successor, assigns, and Affiliates and their officers, directors, employees and agents harmless from and against any and all third-party claims, suits, actions or causes of action and any resulting losses, damages, charges, costs or expenses, (including reasonable attorneys' fees and court costs), arising from or in connection with any (a) breach of representation or warranty or failure to perform any covenant or agreement in this Agreement by said Buyer, (b) any violation of applicable law, regulation or order by said Buyer, (c) any act or omission by the Buyer, with respect to this Agreement first arising, occurring or existing during the term of this Agreement, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination of this Agreement, except to the extent caused by an act of gross negligence or willful misconduct by an officer, director, agent, employee or Affiliate of Seller or its respective successors or assigns.

(c) If any Party intends to seek indemnification under this Section from the other Party with respect to any action or claim, the Party seeking indemnification shall give the other Party notice of such claim or action within thirty (30) days of the later of the commencement of, or actual knowledge of, such claim or action; provided, however, that in the event such notice is delivered more than thirty (30) days after the Party seeking indemnification knows of such claim or action, the indemnifying Party shall be relieved of its indemnity hereunder only if and to the extent such indemnifying Party was actually prejudiced by the delay. The Party seeking indemnification shall have the right, at its sole cost and expense, to participate in the defense of any such claim or action. The Party seeking indemnification shall not compromise or settle any such claim or action without the prior consent of the other Party, which consent shall not be unreasonably withheld.

Section 9.3 Independent Contractor Status

Nothing in this Agreement shall be construed as creating any relationship between the Buyer and Seller other than that of independent contractors for the sale and delivery of Requirements for Default Service.

ARTICLE 10. ASSIGNMENT

Section 10.1 General Prohibition Against Assignments

Except as provided in Section 10.2, neither Party shall assign, pledge or otherwise transfer this Agreement or any right or obligation under this Agreement without first obtaining the other Party’s written consent, which consent shall not be unreasonably withheld.

Section 10.2 Exceptions to Prohibition Against Assignments

(a) Seller may, without the Buyer’s prior written consent, collaterally assign this Agreement in connection with financing arrangements provided that any such collateral assignment that provides for the Buyer to direct payments to the collateral agent (i) shall be in writing, (ii) shall not be altered or amended without prior written notice to the Buyer from both Seller and the collateral agent, and (iii) provided that any payment made by the Buyer to the collateral agent shall discharge the Buyer's obligation as fully and to the same extent as if it had been made to the Seller. Seller must provide the Buyer at least ten (10) days advance written notice of collateral assignment and provide copies of any such assignment and relevant agreements or writings.

(b) The Buyer may assign all or a portion of its rights and obligations under this Agreement to any Affiliate of the Buyer without consent of Seller.

(c) Either Party may, upon written notice to the other Party, assign its rights and obligations hereunder, or transfer such rights and obligations by operation of law, to any entity with which or into which such Party shall merge or consolidate or to which such Party shall transfer all or substantially all of its assets, provided that such other entity agrees to assume the rights and obligations hereunder and be bound by the terms hereof and provided further, that such other entity's creditworthiness is equal to or higher than that of the assignor, in which case the assignor shall be relieved of any obligation or liability hereunder as a result of such assignment.

ARTICLE 11. SUCCESSORS AND ASSIGNS

This Agreement shall inure to the benefit of and shall be binding upon the Parties hereto and their respective successors and permitted assigns.

ARTICLE 12. FORCE MAJEURE

(a) Force Majeure shall include but not be limited to acts of God, earthquakes, fires, floods, storms, strikes, labor disputes, riots, insurrections, acts of war (whether declared or otherwise), acts of governmental, regulatory or judicial bodies, but if and only to the extent that such event or circumstance (i) directly affects the availability of the transmission or distribution facilities of NEPOOL, the Buyer or an Affiliate of the Buyer necessary to provide service to the Buyer's customers which are taking service pursuant to the Retail Delivery Tariff and (ii) it is not within the reasonable control of, or the result of the negligence of, the claiming Party, and which, by the exercise of due diligence, the claiming Party is unable to overcome or avoid or cause to be avoided. Force Majeure shall not be based on (A) fluctuations in Default Service, (B) the cost to a Party to overcome or avoid, or cause to be avoided, the event or circumstance affecting such Party's performance or (C) events affecting the availability or cost of operating any generating facility.

(b) To the extent that either Party is prevented by Force Majeure from carrying out, in whole or in part, its obligations hereunder and (i) such Party gives notice and detail of the Force Majeure to the other Party as soon as practicable after the onset of the Force Majeure, including an estimate of its expected duration and the probable impact on the performance of its obligations hereunder; (ii) the suspension of performance is of no greater scope and of no longer duration than is required by the Force Majeure, and (iii) the Party claiming Force Majeure uses commercially reasonable efforts to remedy or remove the inability to perform caused by Force Majeure, then the affected Party shall be excused from the performance of its obligations prevented by Force Majeure. However, neither Party shall be required to pay for any obligation the performance of which is excused by Force Majeure. This paragraph shall not require the settlement of any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute are contrary to its interest. It is understood and agreed that the settlement of strikes, walkouts, lockouts or other labor disputes shall be entirely within the discretion of the Party involved in the dispute.

(c) No obligations of either Party which arose before the Force Majeure occurrence causing the suspension of performance shall be excused as a result of the Force Majeure.

(d) Prior to the resumption of performance suspended as a result of a Force Majeure occurrence, the Party claiming the Force Majeure shall give the other Party written notice of such resumption.

ARTICLE 13. WAIVERS

No delay or omission in the exercise of any right under this Agreement shall impair any such right or shall be taken, construed or considered as a waiver or relinquishment thereof, but any such right may be exercised from time to time and as often as may be deemed expedient. The waiver of any single breach or default of any term or condition of this Agreement shall not be deemed to constitute the waiver of any other prior or subsequent breach or default of the Agreement or any other term or condition.

ARTICLE 14. LAWS AND REGULATIONS

(a) This Agreement and all rights, obligations, and performances of the Parties hereunder, are subject to all applicable federal and state laws, and to all duly promulgated orders and other duly authorized action of governmental authorities having jurisdiction hereof.

(b) The rates, terms and conditions contained in this Agreement are not subject to change under Section 205 of the Federal Power Act as that section may be amended or superseded, absent the mutual written agreement of the Parties. Each Party irrevocably waives its rights, including its rights under §§ 205-206 of the Federal Power Act, unilaterally to seek or support a change in the rate(s), charges, classifications, terms or conditions of this Agreement or any other agreements entered into in connection with this Agreement. By this provision, each Party expressly waives its right to seek or support: (i) an order from FERC finding that the market-based rate(s), charges, classifications, terms or conditions agreed to by the Parties in the Agreement are unjust and unreasonable; or (ii) any refund with respect thereto. Each Party agrees not to make or support such a filing or request, and that these covenants and waivers shall be binding notwithstanding any regulatory or market changes that may occur hereafter.

(c) Absent the agreement of all Parties to a proposed change, the standard of review for changes to this Agreement proposed by a non-party or the Commission acting sua sponte shall be the "public interest" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) (the "Mobile-Sierra" doctrine).

ARTICLE 15. INTERPRETATION, DISPUTE RESOLUTION

Section 15.1 Governing Law

The Agreement shall be governed by and construed and performed in accordance with the laws of the State of New Hampshire, without giving effect to its conflict of laws principles.

Section 15.2 Dispute Resolution

All disputes between the Buyer and Seller under this Agreement shall be referred, upon notice by one Party to the other Party, to a senior manager of Seller designated by Seller, and a senior manager of the Buyer designated by the Buyer, for resolution on an informal basis as promptly as practicable. In the event the designated senior managers are unable to resolve the dispute within ten (10) days of receipt of the notice, or such other period to which the Parties may jointly agree, such dispute shall be submitted to arbitration and resolved in accordance with the arbitration procedure set forth in this Section. The arbitration shall be conducted in Concord, New Hampshire before a single neutral arbitrator mutually agreed to and appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, Seller and the Buyer shall each choose one arbitrator, who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within ten (10) days select a third arbitrator to act as chairman of the arbitration panel. In either case, the arbitrator(s) shall be knowledgeable in electric utility matters, including wholesale power transactions and power market issues, and shall not have any current or past material business or financial relationships with either Party or a witness for either Party and shall not have a direct or indirect interest in any Party or the subject matter of the arbitration. The arbitrator(s) shall afford each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the then-current arbitration rules of the CPR Institute for Dispute Resolution (formerly known as the Center for Public Resources), unless otherwise mutually agreed by the Parties. There shall be no formal discovery conducted in connection with the arbitration unless otherwise mutually agreed by the Parties; provided, however, that the Parties shall exchange witness lists and copies of any exhibits that they intend to utilize in their direct presentations at any hearing before the arbitrator(s) at least ten (10) days prior to such hearing, along with any other information or documents specifically requested by the arbitrator(s) prior to the hearing. Any offer made and the details of any negotiations to resolve the dispute shall not be admissible in the arbitration or otherwise. Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of his, her or their appointment and shall notify the Parties in writing of such decision and the reasons therefore, and shall make an award apportioning the payment of the costs and expenses of arbitration among the Parties; provided, however, that each Party shall bear the costs and expenses of its own attorneys, expert witnesses and consultants unless the arbitrator(s), based upon a determination of good cause, awards attorneys fees and legal and other costs to the prevailing Party. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Agreement and shall have no power to modify or change the Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction, subject expressly to Section 15.3. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute

Resolution Act. Nothing in this paragraph shall impair the ability of a Party to exercise any right or remedy it has under this Agreement, including those in Article 7.

Section 15.3 Venue; Waiver of Jury Trial

Each Party hereto irrevocably (i) submits to the exclusive jurisdiction of the federal and state courts located in the State of New Hampshire; (ii) waives any objection which it may have to the laying of venue of any proceedings brought in any such court; and (iii) waives any claim that such proceedings have been brought in an inconvenient forum. EACH PARTY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY SUIT, ACTION OR PROCEEDING RELATING TO THIS AGREEMENT.

ARTICLE 16. SEVERABILITY

Any provision declared or rendered unlawful by any applicable court of law or regulatory agency or deemed unlawful because of a statutory change will not otherwise affect the remaining provisions and lawful obligations that arise under this Agreement. If any provision of this Agreement, or the application thereof to any Party or any circumstance, is invalid or unenforceable, (a) a suitable and equitable provision shall be substituted therefor in order to carry out, so far as may be valid and enforceable, the intent and purpose of such invalid or unenforceable provision, and (b) the remainder of this Agreement and the application of such provision or circumstances shall not be affected by such invalidity or unenforceability.

ARTICLE 17. MODIFICATIONS

No modification or amendment of this Agreement will be binding on any Party unless it is in writing and signed by both Parties.

ARTICLE 18. ENTIRE AGREEMENT

This Agreement, including the Appendices, the tariffs and agreements referred to herein or therein, embody the entire agreement and understanding of the Parties in respect of the transactions contemplated by this Agreement. There are no restrictions, promises, representations, warranties, covenants or undertakings, other than those expressly set forth or referred to herein or therein. It is expressly acknowledged and agreed that there are no restrictions, promises, representations, warranties, covenants or undertakings contained in any material provided or otherwise made available by the Seller or the Buyer to each other. This Agreement supersedes all prior agreements and understandings between the Parties with respect to the transactions contemplated hereby.

ARTICLE 19. COUNTERPARTS

This Agreement may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

ARTICLE 20. INTERPRETATION; CONSTRUCTION

The article and section headings contained in this Agreement are solely for the purpose of reference, are not part of the agreement of the Parties and shall not in any way affect the meaning or interpretation of this Agreement. For purposes of this Agreement, the term "including" shall mean "including, without limitation". The Parties acknowledge that, each Party and its counsel have reviewed and or revised this Agreement and that any rule of construction to the effect that any ambiguities are to be resolved against the drafting Party shall not be employed in the interpretation of this Agreement, and it is the result of joint discussion and negotiation.

ARTICLE 21. REPRESENTATIONS; WARRANTIES AND COVENANTS

Each Party represents to the other Party, upon execution and continuing throughout the term of this Agreement, as follows:

(a) It is duly organized in the form of business entity set forth in the first paragraph of this Agreement, validly existing and in good standing under the laws of its state of its organization and has all requisite power and authority to carry on its business as is now being conducted, including all regulatory authorizations as necessary for it to legally perform its obligations hereunder.

(b) It has full power and authority to execute and deliver this Agreement and to consummate and perform the transactions contemplated hereby. This Agreement has been duly and validly executed and delivered by it, and, assuming that this Agreement constitutes a valid and binding agreement of the other Party, constitutes its valid and binding agreement, enforceable against it in accordance with its terms, subject to bankruptcy, insolvency, fraudulent transfer, reorganization, moratorium and similar laws of general applicability relating to or affecting creditors' rights and to general equity principles.

(c) Such execution, delivery and performance do not violate or conflict with any law applicable to it, any provision of its constitutional documents, or the terms of any note, bond, mortgage, indenture, deed of trust, license, franchise, permit, concession, contract, lease or other instrument to which it is bound, any order or judgment of any court or other agency of government applicable to it or any of its assets or any contractual restriction binding on or affecting it or any of its assets.

(d) No declaration, filing with, notice to, or authorization, permit, consent or approval of any governmental authority is required for the execution and delivery of this Agreement by it or the performance by it of its obligations hereunder, other than such declarations, filings, registrations, notices, authorizations, permits, consents or approvals which, if not obtained or made, will not, in the aggregate, have a Material Adverse Effect.

(e) Neither the execution and delivery of this Agreement by it will nor the performance by it of its obligations under this Agreement will or does (i) conflict with or result in any breach of any provision of its Governing Documents, (ii) result in a default (or give rise to any right of termination, cancellation or acceleration) under any of the terms, conditions or provisions of any note, bond, mortgage, indenture, license, agreement or other instrument or obligation to which it or any of its subsidiaries is a party or by which it or any of its subsidiaries is bound, except for such defaults (or rights of termination, cancellation or acceleration) as to which requisite waivers or consents have been obtained or which, in the aggregate, would not have a Material Adverse Effect; or (iii) violate any order, writ, injunction, decree, statute, rule or regulation applicable to it, which violation would have a Material Adverse Effect.

(f) There are no claims, actions, proceedings or investigations pending or, to its knowledge, threatened against or relating to it before any governmental authority acting in an adjudicative capacity relating to the transactions contemplated hereby that could have a Material Adverse Effect. It is not subject to any outstanding judgment, rule, order, writ, injunction or decree of any court or governmental authority which, individually or in the aggregate, would create a Material Adverse Effect.

(g) There are no bankruptcy, insolvency, reorganization, receivership or other similar proceedings pending or being contemplated by it, or of its knowledge threatened against it.

(h) It is a signatory to the Market Participant Service Agreement and is in compliance with all ISO Rules, including the ISO Financial Assurance Policy.

(i) It is acting for its own account, has made its own independent decision to enter into this Agreement and as to whether this Agreement is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party hereto, and is capable of assessing the merits of and understanding, and understands and accepts, the terms, conditions and risks of this Agreement.

ARTICLE 22. CONSENTS AND APPROVALS

The Parties shall cooperate so that each Party may take such actions as necessary and required for the other Party to effectuate and comply with this Agreement including to (i) promptly prepare and file all necessary documentation, (ii) effect all necessary applications, notices, petitions and filings and execute all agreements and documents, and (iii) use all commercially reasonable efforts to obtain all necessary consents, approvals and authorizations of all other entities, in the case of each of the foregoing clauses (i), (ii) and (iii), necessary or advisable to consummate the transactions contemplated by this Agreement. The Buyer shall have the right to review and approve in advance all characterizations of the information relating to the transactions contemplated by this Agreement which appear in any filing, press release or public announcement made in connection with the transactions contemplated hereby.

ARTICLE 23. CONFIDENTIALITY

Seller acknowledges that Seller's identity will be publicly disclosed in the NHPUC order approving or denying the Buyer's inclusion in retail rates of the amounts payable by Buyer to Seller under this Agreement as described in Section 3.8. Neither Seller nor the Buyer shall provide copies of this Agreement or disclose the contents thereof (the "Confidential Terms") to any third party without the prior written consent of the other Party; provided, however, that either Party may provide a copy of the Confidential Terms, in whole or in part to (1) any regulatory agency requesting and/or requiring such Confidential Terms, provided that any such disclosure must include a request for confidential treatment of the Confidential Terms, and (2) an Affiliate if related to the Party's performance of its obligations hereunder, provided that such Affiliate agrees to treat the Confidential Terms as confidential in accordance with this clause.

[Remainder of Page Intentionally Left Blank]

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute this Agreement on their behalf as of the date first above written.

UNITIL ENERGY SYSTEMS, INC.

BY: ____

Joseph Conneely

Vice President

[COMPANY]

BY: ____

Its ____

APPENDIX A

Service Requirements Matrix
By Service Requirement, Load Asset Name and ID, Load Responsibility,
and Applicable Period

[List All Active Transactions]

For service pursuant to Buyer's RFP issued on **May 7, 2024**

Service Requirement	Load Asset Name and ID	Load Responsibility	Schedule 1	Schedule 2
UES Small Default Load	Small Customer Group, 11451	90%	August 1, 2024	January 31, 2025
UES Medium Default Load	Medium Customer Group, 11452	90%	August 1, 2024	January 31, 2025
UES Large Customer Group	UES Large Default Load, 10019	100%	August 1, 2024	January 31, 2025

APPENDIX B

Monthly Contract Rate by Service Requirement
Dollars per MWh

For service pursuant to Buyer's RFP issued on **May 7, 2024**

Service Requirement	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25
90% UES Small Customer Group (6 months)						

Service Requirement	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25
90% UES Medium Customer Group (6 months)						

The following are Fixed Monthly Adders. Please refer to Section 5.1 for calculation of Contract Rate						
Service Requirement	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25
100% UES Large Customer Group (6 months)						

APPENDIX C

POINTS OF INTERCONNECTION, REFERRED TO AS
DELIVERY POINT

Points of Interconnection	Nominal Delivery Voltage	Metering Point	Nominal Metering Voltage
Garvins (1)	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV
New Hampshire Hydro			
Lower Penacook Falls (2)	3ϕ, 4 wire, 19.9/34.5 kV	At Connection Point	3ϕ, 4 wire, 19.9/34.5 kV
Upper Penacook Falls (2)	3ϕ, 4 wire, 19.9/34.5 kV	At Connection Point	3ϕ, 4 wire, 19.9/34.5 kV
Briar Hydro (2)	3ϕ, 4 wire, 19.9/34.5 kV	At Connection Point	3ϕ, 4 wire, 19.9/34.5 kV
SES Concord Company L.P. (2)	3ϕ, 4 wire, 19.9/34.5 kV	At Connection Point	3ϕ, 4 wire, 19.9/34.5 kV
Broken Ground	3ϕ, 115 kV	At Curtisville Sending Point	3ϕ, 115 kV
Penacook (1)	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV
Guinea (1)	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV
Kingston (1)	3ϕ, 115 kV	At Peaslee Sending Point	3ϕ, 115 kV
Timber Swamp (1)	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV
Great Bay (1)	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV

(1) Substation delivery point

(2) Small power producer purchase delivery points.

AMENDMENT No. [X]

OF

POWER SALES AGREEMENT

This Amendment No. [X] ("Amendment No. [X]"), dated and effective as of **June 5, 2024** (the "Effective Date"), amends the Power Sales Agreement, dated [DATE] (the "Agreement") between UNITIL ENERGY SYSTEMS, INC. ("Buyer") and [COMPANY NAME] ("Seller") (collectively, the "Parties").

Notwithstanding Article 21(d) of the Agreement or anything else to the contrary in either this Amendment No. [X] or the Agreement, the Parties' obligations under this Amendment No. [X] are subject to Buyer obtaining approval from the NHPUC of the inclusion in retail rates of the amounts payable by Buyer to Seller under this Amendment No. [X], without material modification to the obligations of either Party under this Amendment No. [X]. Buyer shall use its best efforts to obtain prompt approval of such rates. If Buyer is unable to obtain NHPUC approval by **June 14, 2024**, Buyer and Seller agree to review the status of such approval process and determine whether to continue to pursue the transaction contemplated in this Amendment No. [X]. If the Parties cannot agree as to how to continue such transaction, this Amendment No. [X] shall terminate and be null and void without liability to either Party.

Buyer shall bear the cost of the NHPUC filing described above except for any costs associated with Seller's intervention. Buyer shall request that the NHPUC give confidential treatment to the terms of this Amendment No. [X], which is the result of a competitive solicitation held by Buyer.

The Parties hereby agree to further amend the Agreement as follows:

1. Appendix A is amended as attached hereto. The amendment adds a new section reflecting the results of the RFP issued by Buyer on May 7, 2024.
2. Appendix B is amended as attached hereto. The amendment adds pricing associated with the results of the RFP issued by Buyer on May 7, 2024.
3. Appendix B indicates that the prices listed for the Large Customer Group are Fixed Monthly Adders, therefore the Contract Rate will be calculated as the sum of the Average Weighted RT LMP and the Fixed Monthly Adder as shown in Equation 1. The Average Weighted RT LMP is calculated in accordance with Equation 2.

Equation 1

$$Contract\ Rate = Average\ Weighted\ RT\ LMP + Fixed\ Monthly\ Adder$$

The Average Weighted RT LMP shall be calculated using the MWH of Delivered Energy reported for the Large Customer Group default service load asset, Load Asset number 10019, and the hourly real time locational marginal prices ("RT

LMP") for the settlement location of Load Asset 10019, which is currently the New Hampshire Load Zone (4002). The Average Weighted RT LMP equals the sum of the products of the RT LMP and the Delivered Energy (MWH) of Load Asset 10019 in each hour of the month of service, divided by the sum of Delivered Energy (MWH) of Load Asset 10019 for the month of service, as shown in Equation 2.

Equation 2

$$Average\ Weighted\ RT\ LMP = \frac{Sum\ [hourly\ RT\ LMP\ *\ hourly\ Delivered\ Energy\ (MWH)\ of\ Load\ Asset\ 10}{Sum\ [hourly\ Delivered\ Energy\ (MWH)\ of\ Load\ Asset\ 10019]}$$

The Large Customer Group prices listed in Appendix B are Fixed Monthly Adders requiring the Contract Rate to be calculated as described in Equation 1 and Equation 2, and the Contract Rate will be determined and affirmed by both Buyer and Seller by the third business day following the month of service. Once agreed upon, the Contract Rate for the month of service shall be final and shall not be subject to change in the event that either the New Hampshire RT LMP or the Delivered Energy (MWH) of Load Asset 10019 are subsequently revised or restated.

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute and deliver this Amendment No. [X] to the Agreement effective as of the Effective Date.

Unitil Energy Systems, Inc.

BY: ______________________________________

Joseph Conneely

Vice President

[Seller]

BY: ______________________________________

Its______________________________

REDACTED

APPENDIX A

Service Requirements Matrix
By Service Requirement, Load Asset Name and ID, Load Responsibility,
and Applicable Period

[List All Active Transactions]

For service pursuant to Buyer's RFP issued on **May 7, 2024**

Service Requirement	Load Asset Name and ID	Load Responsibility	Schedule 1	Schedule 2
UES Small Default Load	Small Customer Group, 11451	90%	August 1, 2024	January 31, 2025
UES Medium Default Load	Medium Customer Group, 11452	90%	August 1, 2024	January 31, 2025
UES Large Customer Group	UES Large Default Load, 10019	100%	August 1, 2024	January 31, 2025

REDACTED

APPENDIX B

Monthly Contract Rate by Service Requirement
Dollars per MWh

For service pursuant to Buyer's RFP issued on **October 31, 2023**

[List All Active Transactions]

Service Requirement	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25
90% UES Small Customer Group (6 months)						

Service Requirement	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25
90% UES Medium Customer Group (6 months)						

The following are Fixed Monthly Adders. Please refer to Section 5.1 for calculation of Contract Rate						
Service Requirement	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25
100% UES Large Customer Group (6 months)						

MUTUAL CONFIDENTIAL NON-DISCLOSURE AGREEMENT

This MUTUAL CONFIDENTIAL NON-DISCLOSURE AGREEMENT is made as of __________________, 201_ between ___________________________ ("Company"), having a place of business at ________________________________, and Unitil Energy Systems, Inc. ("Unitil") having a principal place of business at 6 Liberty Lane West, Hampton, NH 03842, (together "the Parties," individually "a Party"). The Parties hereby agree that disclosures of Confidential Information shall be governed by the following terms and conditions. A Party receiving Confidential Information under this Agreement is referred to as "Recipient," and a Party disclosing Information is referred to as "Discloser."

1. **Definition of Confidential Information**. "Confidential Information" means any oral, written, graphic or machine-readable information including, but not limited to, any and all confidential and proprietary information relating to the Purpose, the Discloser, its affiliates or subsidiaries, and including all information or material that has or could have commercial value or other use in the business or the prospective business of the Discloser, disclosed by the Discloser to the Recipient in connection with this Agreement and the Purpose, whether committed to memory or embodied in writing or other tangible form. Confidential Information includes, without limitation, contracts, fees, accounts, records, customer and client information, agreements and any other incident of the Discloser's business disclosed to the Recipient, in each case provided in connection with this Agreement and Purpose. Confidential Information does not include any information which Recipient can document: (a) is known to Recipient or any of its Representatives on the non-confidential basis prior to the time of disclosure; (b) is independently developed by Recipient without use of the Confidential Information; (c) becomes known to Recipient from another source without confidentiality restriction on subsequent disclosure or use; (d) is or becomes part of the public domain through no wrongful act of Recipient; or (e) is information approved for disclosure or release by the Recipient by written authorization from the Discloser. Confidential Information does not include any source code or technical information subject to a license that meets the requirements of the Open source Definition. The Open Source Definition is found at http://www.opensource.org/osd.html.

2. **Purpose for Disclosure.** The parties may only use Confidential Information for the following purposes (the "Purpose"):
   - Negotiation of potential power supply and/or renewable energy credits purchase and sales transactions ("Transactions").
   - Negotiation of a potential base contract(s) or master agreement(s) pertaining to any Transactions ("Base Contracts").
   - Evaluation of either Parties creditworthiness in the context of either potential or existing Transactions and/or Base Contracts.
3. **Non-Disclosure of Confidential Information.** Recipient agrees: (i) to use the same degree of care, but no less than a reasonable degree of care, to protect against the unauthorized disclosure of Discloser's Confidential Information as it uses to protect its own Confidential Information; (ii) not to divulge any such Confidential Information or any information derived therefrom to any third person; (iii) not to make any use whatsoever at any time of such Confidential Information except as necessary in accordance with the Purpose; (iv) not to copy or reverse engineer any such Confidential Information; and (v) not to export or re-export (within the meaning of U.S. or other export control laws or regulations) any such Confidential Information or product thereof. Recipient agrees to disclose Confidential Information only to its directors, officers, employees, consultants, agents or independent contractors (its "Representatives") with a direct need to know to effect the Purpose, and who are bound by legally enforceable obligations of confidentiality no less restrictive than the terms of this Agreement. Recipient shall not remove the proprietary notices from Confidential Information. Each Party agrees to promptly notify the other Party in writing of any misuse or misappropriation of Confidential Information of the other Party of which it becomes aware.
4. **Mandatory Disclosure**. In the event that Recipient or its Representatives is requested or required by any competent judicial, governmental or regulatory body or by legal process or applicable regulations or laws to disclose any of the Confidential Information of Discloser, Recipient shall give prompt notice so that Discloser may seek a protective order or other appropriate relief. If such protective order is not

obtained, Recipient shall disclose only that portion of the Confidential Information that its counsel advises that it is legally required to disclose.

5. **Remedies.** Recipient acknowledges and agrees that due to the unique nature of Discloser's Confidential Information, there may be no adequate remedy at law for any breach of Recipient's obligations hereunder, which breach may result in irreparable harm to the Discloser and therefore, that upon any such breach of any threat thereof, the Discloser shall be entitled to seek appropriate equitable relief in addition to whatever remedies it might have at law.
6. **Term.** The foregoing commitments of each Party shall survive any termination of the Purpose, and shall remain in effect with respect to any particular Confidential Information unless and until the Recipient can document that one of the exceptions stated in Section 1 applies, or unless mutually agreed, as evidenced by writing, to a shorter period.
7. **No Additional Agreements; No Prohibition on Agreements**. Nothing herein shall obligate either Party to disclose any Confidential Information or negotiate or enter into any agreement or relationship with the other Party. Nothing herein shall prohibit a Party from entering into any arrangement or agreement with a third party.
8. **No Warranty**. The Parties understand and agree that Confidential Information is provided "as is"; neither Party shall have any responsibility to the other based on any claim that any information furnished hereunder was incorrect, incomplete, or defective in any way. Neither Party makes any warranties, whether express, implied or statutory, regarding the sufficiency of the information disclosed for any purpose, including warranties of merchantability, fitness for a particular purpose, and non-infringement.
9. **General.** (a) Assignment. This Agreement is not assignable or transferable by either Party; any attempted assignment will be void and without effect, unless such assignment is agreed to in writing by both Parties. (b) No Other Rights. No rights, title, license of any kind in any Confidential Information is provided hereunder, either expressly or by implication, estoppel or otherwise. (c) No Agency. This Agreement does not create any agency or partnership relationship. (d) No Waiver. No waiver of

any provision of this Agreement, or a breach of this Agreement shall be effective unless it is in writing, signed by the Party waiving the provision or the breach. No waiver of a breach of this Agreement (whether express or implied) shall constitute a waiver of a subsequent breach of this Agreement. (e) Choice of Law. This Agreement will be governed by and interpreted in accordance with the laws of the State of New Hampshire, excluding its choice of laws rules. (f) Complete Agreement. This Agreement constitutes the complete agreement between the Parties on the subject matter identified herein. Any modifications to this Agreement must be made in writing and signed by both Parties.

Unitil Energy Systems, Inc.	**(Company)**
By:______________________________	By:______________________________
______________________________	______________________________
NAME (PRINT OR TYPE)	NAME (PRINT OR TYPE)
TITLE:__________________________	TITLE:__________________________
Date:___________________________	Date:___________________________

Unitil Energy Systems, Inc.
Customer Migration Report

RETAIL SALES (kWh) by CUSTOMER CLASS
Competitive Generation Sales

Month	DOMESTIC	REGULAR GENERAL	LARGE GENERAL	OUTDOOR LIGHTING	TOTAL
Apr-23	4,372,897	11,334,198	20,875,155	210,578	36,792,828
May-23	4,420,865	11,889,120	21,618,603	214,038	38,142,626
Jun-23	7,569,106	13,243,122	22,441,247	231,225	43,484,700
Jul-23	11,429,085	16,578,612	25,193,179	226,284	53,427,160
Aug-23	11,480,823	16,546,252	28,429,526	233,101	56,689,702
Sep-23	10,091,591	15,350,595	27,096,540	228,836	52,767,562
Oct-23	8,046,430	13,850,100	25,279,002	226,189	47,401,721
Nov-23	8,420,652	12,905,655	23,485,679	232,486	45,044,472
Dec-23	9,920,188	13,370,012	23,054,990	238,540	46,583,730
Jan-24	11,001,192	14,242,706	22,984,609	229,616	48,458,123
Feb-24	11,549,065	15,200,731	26,081,357	231,410	53,062,563
Mar-24	9,467,750	14,143,942	23,879,880	229,985	47,721,557
Apr-24	10,116,521	13,271,895	22,900,128	224,034	46,512,578

RETAIL SALES (kWh) by CUSTOMER CLASS
Total Sales

Month	DOMESTIC	REGULAR GENERAL	LARGE GENERAL	OUTDOOR LIGHTING	TOTAL
Apr-23	34,145,447	22,569,830	24,404,748	440,458	81,560,483
May-23	32,299,047	22,656,011	25,479,468	493,123	80,927,649
Jun-23	33,572,599	23,155,377	26,519,028	491,776	83,738,780
Jul-23	49,276,395	29,116,330	30,217,311	477,406	109,087,442
Aug-23	49,201,669	28,265,919	29,874,700	489,786	107,832,074
Sep-23	42,857,831	25,929,133	28,416,899	481,869	97,685,732
Oct-23	33,995,147	23,049,050	26,548,036	473,556	84,065,789
Nov-23	34,284,978	21,459,153	24,572,113	482,282	80,798,526
Dec-23	40,637,134	22,978,726	24,103,509	487,374	88,206,743
Jan-24	45,030,013	24,644,292	24,107,407	478,345	94,260,057
Feb-24	47,398,961	26,716,179	27,291,151	477,694	101,883,985
Mar-24	40,086,939	24,395,975	25,094,654	473,774	90,051,342
Apr-24	35,293,644	22,080,520	23,994,855	456,001	81,825,020

RETAIL SALES (kWh) by CUSTOMER CLASS
Competitive Generation Sales as a Percentage of Total Sales

Month	DOMESTIC	REGULAR GENERAL	LARGE GENERAL	OUTDOOR LIGHTING	TOTAL
Apr-23	12.8%	50.2%	85.5%	47.8%	45.1%
May-23	13.7%	52.5%	84.8%	43.4%	47.1%
Jun-23	22.5%	57.2%	84.6%	47.0%	51.9%
Jul-23	23.2%	56.9%	83.4%	47.4%	49.0%
Aug-23	23.3%	58.5%	95.2%	47.6%	52.6%
Sep-23	23.5%	59.2%	95.4%	47.5%	54.0%
Oct-23	23.7%	60.1%	95.2%	47.8%	56.4%
Nov-23	24.6%	60.1%	95.6%	48.2%	55.7%
Dec-23	24.4%	58.2%	95.6%	48.9%	52.8%
Jan-24	24.4%	57.8%	95.3%	48.0%	51.4%
Feb-24	24.4%	56.9%	95.6%	48.4%	52.1%
Mar-24	23.6%	58.0%	95.2%	48.5%	53.0%
Apr-24	28.7%	60.1%	95.4%	49.1%	56.8%

Unitil Energy Systems, Inc.
Customer Migration Report

CUSTOMER COUNT by CLASS
Customers Served by Competitive Generation

Month	DOMESTIC	REGULAR GENERAL	LARGE GENERAL	OUTDOOR LIGHTING	TOTAL
Apr-23	7,780	3,222	135	412	11,549
May-23	14,065	4,015	134	521	18,735
Jun-23	14,765	4,015	134	532	19,446
Jul-23	14,882	4,103	145	542	19,672
Aug-23	14,901	4,133	145	542	19,721
Sep-23	14,913	4,148	145	550	19,756
Oct-23	14,788	4,153	146	554	19,641
Nov-23	14,720	4,150	146	557	19,573
Dec-23	14,920	4,201	145	562	19,828
Jan-24	14,788	4,209	145	564	19,706
Feb-24	14,664	4,211	144	568	19,587
Mar-24	17,210	4,552	145	609	22,516
Apr-24	17,458	4,531	145	610	22,744

Total Customers

Month	DOMESTIC	REGULAR GENERAL	LARGE GENERAL	OUTDOOR LIGHTING	TOTAL
Apr-23	67,867	11,202	169	1,627	80,865
May-23	67,484	11,140	167	1,623	80,414
Jun-23	67,462	11,142	167	1,622	80,393
Jul-23	67,442	11,144	167	1,621	80,374
Aug-23	67,465	11,144	167	1,618	80,394
Sep-23	67,435	11,150	167	1,614	80,366
Oct-23	67,543	11,141	167	1,614	80,465
Nov-23	68,607	11,245	167	1,613	81,632
Dec-23	68,637	11,171	167	1,612	81,587
Jan-24	68,658	11,171	167	1,609	81,605
Feb-24	68,693	11,184	166	1,607	81,650
Mar-24	68,505	11,188	166	1,607	81,466
Apr-24	67,713	11,104	165	1,603	80,585

CUSTOMER COUNT by CLASS
Percentage of Customers Served by Competitive Generation

Month	DOMESTIC	REGULAR GENERAL	LARGE GENERAL	OUTDOOR LIGHTING	TOTAL
Apr-23	11.5%	28.8%	79.9%	25.3%	14.3%
May-23	20.8%	36.0%	80.2%	32.1%	23.3%
Jun-23	21.9%	36.0%	80.2%	32.8%	24.2%
Jul-23	22.1%	36.8%	86.8%	33.4%	24.5%
Aug-23	22.1%	37.1%	86.8%	33.5%	24.5%
Sep-23	22.1%	37.2%	86.8%	34.1%	24.6%
Oct-23	21.9%	37.3%	87.4%	34.3%	24.4%
Nov-23	21.5%	36.9%	87.4%	34.5%	24.0%
Dec-23	21.7%	37.6%	86.8%	34.9%	24.3%
Jan-24	21.5%	37.7%	86.8%	35.1%	24.1%
Feb-24	21.3%	37.7%	86.7%	35.3%	24.0%
Mar-24	25.1%	40.7%	87.3%	37.9%	27.6%
Apr-24	25.8%	40.8%	87.9%	38.1%	28.2%

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
RPS Compliance Cost Estimates, Non-G1 Customers

RPS Obligation / **Market Price Assumptions** / **Non-G1 Customer Costs**

		2		3	4	5	2		3	4	5	7							
Year	**Month**	**Class I***	**Class I Carve Out**	**Class II**	**Class III**	**Class IV**	**Class I***	**Class I Carve Out**	**Class II**	**Class III**	**Class IV**	**Non-G1 Sales (MWH)**	**Class I***	**Class I Carve Out**	**Class II**	**Class III**	**Class IV**	**RPS Cost**	**Cost $/MWH**
2024	Aug-24	11.9%	2.20%	0.70%	8.0%	1.5%	$ 39.80	$ 28.28	$ 38.00	$ 40.23	$ 29.75	52,894	$ 250,516	$ 32,908	$ 14,070	$ 170,234	$ 23,604	$ 491,332	$ 9.29
2024	Sep-24	11.9%	2.20%	0.70%	8.0%	1.5%	$ 39.80	$ 28.28	$ 38.00	$ 40.23	$ 29.75	44,459	$ 210,568	$ 27,661	$ 11,826	$ 143,088	$ 19,840	$ 412,982	$ 9.29
2024	Oct-24	11.9%	2.20%	0.70%	8.0%	1.5%	$ 39.80	$ 28.28	$ 38.00	$ 40.23	$ 29.75	36,665	$ 173,655	$ 22,812	$ 9,753	$ 118,004	$ 16,362	$ 340,586	$ 9.29
2024	Nov-24	11.9%	2.20%	0.70%	8.0%	1.5%	$ 39.80	$ 28.28	$ 38.00	$ 40.23	$ 29.75	35,972	$ 170,370	$ 22,380	$ 9,569	$ 115,772	$ 16,052	$ 334,143	$ 9.29
2024	Dec-24	11.9%	2.20%	0.70%	8.0%	1.5%	$ 39.80	$ 28.28	$ 38.00	$ 40.23	$ 29.75	44,322	$ 209,916	$ 27,575	$ 11,790	$ 142,645	$ 19,779	$ 411,704	$ 9.29
2025	Jan-25	12.8%	2.20%	0.70%	8.0%	1.5%	$ 39.75	$ 28.28	$ 38.00	$ 40.23	$ 29.75	51,079	$ 259,891	$ 31,779	$ 13,587	$ 164,393	$ 22,794	$ 492,444	$ 9.64

*Class I is the net requirement which is the gross requirement less the Class I Thermal Carve-Out requirement.
2024 - 14.1% - 2.2%
2025 - 15.0% - 2.2%

REDACTED

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
RPS Compliance Cost Estimates, G1 Customers

RPS Obligation

Year	Month	Class I* (2)	Class I Carve Out	Class II (3)	Class III (4)	Class IV (5)
2024	Aug-24	11.9%	2.20%	0.70%	8.0%	1.5%
2024	Sep-24	11.9%	2.20%	0.70%	8.0%	1.5%
2024	Oct-24	11.9%	2.20%	0.70%	8.0%	1.5%
2024	Nov-24	11.9%	2.20%	0.70%	8.0%	1.5%
2024	Dec-24	11.9%	2.20%	0.70%	8.0%	1.5%
2025	Jan-25	12.8%	2.20%	0.70%	8.0%	1.5%

Market Price Assumptions

Year	Month	Class I* (2)	Class I Carve Out	Class II (3)	Class III (4)	Class IV (5)
2024	Aug-24	$ 39.80	$ 28.28	$ 38.00	$ 40.23	$ 29.75
2024	Sep-24	$ 39.80	$ 28.28	$ 38.00	$ 40.23	$ 29.75
2024	Oct-24	$ 39.80	$ 28.28	$ 38.00	$ 40.23	$ 29.75
2024	Nov-24	$ 39.80	$ 28.28	$ 38.00	$ 40.23	$ 29.75
2024	Dec-24	$ 39.80	$ 28.28	$ 38.00	$ 40.23	$ 29.75
2025	Jan-25	$ 39.75	$ 28.28	$ 38.00	$ 40.23	$ 29.75

G1 Customer Costs

Year	Month	G1 Sales (MWH) (7)	Class I*	Class I Carve Out	Class II	Class III	Class IV	RPS Cost	Cost $/MWH
2024	Aug-24	1,365	$ 6,463	$ 849	$ 363	$ 4,392	$ 609	$ 12,676	$ 9.29
2024	Sep-24	1,261	$ 5,971	$ 784	$ 335	$ 4,057	$ 563	$ 11,711	$ 9.29
2024	Oct-24	1,143	$ 5,411	$ 711	$ 304	$ 3,677	$ 510	$ 10,613	$ 9.29
2024	Nov-24	1,081	$ 5,121	$ 673	$ 288	$ 3,480	$ 482	$ 10,043	$ 9.29
2024	Dec-24	1,121	$ 5,308	$ 697	$ 298	$ 3,607	$ 500	$ 10,411	$ 9.29
2025	Jan-25	1,138	$ 5,789	$ 708	$ 303	$ 3,662	$ 508	$ 10,968	$ 9.64

*Class I is the net requirement which is the gross requirement less the Class I Thermal Carve-Out requirement.
2024 - 14.1% - 2.2%
2025 - 15.0% - 2.2%

UES Default Service RFP Issued May 7, 2024
For Loads to be Served beginning August 1, 2024
Historical Pricing by Customer Group, No Longer Confidential*

	Non-G1 Purchases (MWH)	Wtd Avg Price	Change Prior Period	Change Prior Year	G1 Purchases (MWH)	Wtd Avg Price	Change Prior Period	Change Prior Year
May-19	46,986	$ 69.32	-33%	1%	3,345	$ 57.16	-25%	-13%
Jun-19	46,681				3,702			
Jul-19	62,361				4,245			
Aug-19	67,002				4,030	$ 51.49	-10%	-36%
Sep-19	52,879				3,829			
Oct-19	54,993				3,861			
Nov-19	48,082	$ 90.14	30%	-13%	3,342	$ 68.36	33%	-22%
Dec-19	55,151				3,586			
Jan-20	64,846				3,461			
Feb-20	61,007				3,466	$ 53.96	-21%	-29%
Mar-20	54,444				3,478			
Apr-20	50,230				3,229			
May-20	46,070	$ 51.23	-43%	-26%	3,244	$ 47.14	-13%	-18%
Jun-20	52,981				4,559			
Jul-20	65,465				4,995			
Aug-20	61,604				4,678	$ 48.62	3%	-6%
Sep-20	56,863				4,726			
Oct-20	48,292				4,073			
Nov-20	48,417	$ 74.76	46%	-17%	3,690	$ 66.69	37%	-2%
Dec-20	62,281				4,667			
Jan-21	62,839				4,304			
Feb-21	62,244				4,405	$ 76.71	15%	42%
Mar-21	54,524				4,261			
Apr-21	51,458				4,294			
May-21	47,389	$ 52.71	-29%	3%	4,622	$ 58.04	-24%	23%
Jun-21	50,816				3,997			
Jul-21	56,487				4,449			
Aug-21	67,064				4,622	$ 74.71	29%	54%
Sep-21	60,128				4,297			
Oct-21	45,181				3,856			
Nov-21	47,466	$ 149.44	184%	100%	3,815	$ 112.96	51%	69%
Dec-21	59,483				4,387			
Jan-22	61,901				4,150			
Feb-22	59,300				4,183	$ 102.70	-9%	34%
Mar-22	54,283				4,206			
Apr-22	51,132				4,247			
May-22	45,865	$ 81.01	-46%	54%	4,102	$ 103.65	1%	79%
Jun-22	50,014				5,022			
Jul-22	62,434				5,465			
Aug-22	70,399				5,785	$ 94.65	-9%	27%
Sep-22	56,477				5,293			
Oct-22	47,477				4,910			
Nov-22	51,110	$ 267.40	230%	79%	4,756	$ 110.50	17%	-2%
Dec-22	57,434				4,471			
Jan-23	63,602				4,670			
Feb-23	63,237				4,557	$ 78.15	-29%	-24%
Mar-23	57,239				4,555			
Apr-23	51,116				4,341			
May-23	48,733	$ 98.48	-63%	22%	4,614	$ 64.44	-18%	-38%
Jun-23	49,611				4,698			
Jul-23	62,455				5,190			
Aug-23	69,228				5,037	$ 56.82	-12%	-40%
Sep-23	54,354				4,399			
Oct-23	47,839				4,220			
Nov-23	47,800	$ 138.85	41%	-48%	3,827	$ 80.32	41%	-27%
Dec-23	57,022				4,110			
Jan-24	60,971				4,141			
Feb-24	54,260				3,547	$ 54.33	-32%	-30%
Mar-24	51,186				3,447			
Apr-24	44,277				3,366			

* Historical pricing shown has previously been required to be submitted to FERC under its Electronic Quarterly Reporting requirements.

Unitil Energy Systems DE 24-065
Schedule JMP-6
Page 1 of 3

Table 1 - ISO Market Tranche Price Estimate (10% Load Requirements) - Small Customer Group

	NH Wholesale Load Cost Components	Unit	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25
A	Projected Default Service Volume	MWh	4,198	3,468	2,800	2,771	3,536	4,143
B	Total ISO Market Tranche Estimate	$ / MWh	$ 57.72	$ 51.28	$ 52.39	$ 67.58	$ 93.50	$ 119.84
C	Energy Price	$ / MWh	$ 45.66	$ 37.40	$ 36.01	$ 51.07	$ 79.81	$ 107.66
D	Capacity Price	$ / MWh	$ 8.63	$ 10.45	$ 12.95	$ 13.09	$ 10.26	$ 8.76
E	Net Commitment Period Compensation	$ / MWh	$ 0.94	$ 0.94	$ 0.94	$ 0.94	$ 0.94	$ 0.94
F	Ancillary Markets	$ / MWh	$ 1.76	$ 1.76	$ 1.76	$ 1.76	$ 1.76	$ 1.76
G	Misc Credit/Charge	$ / MWh	$ (0.32)	$ (0.32)	$ (0.32)	$ (0.32)	$ (0.32)	$ (0.32)
H	Wholesale Market Service Charge	$ / MWh	$ 1.05	$ 1.05	$ 1.05	$ 1.05	$ 1.05	$ 1.05

I	**Period Weighted Average Price**	**$ 75.60**

Table 1 - ISO Market Tranche Price Estimate (10% Load Requirements) - Medium Customer Group

	NH Wholesale Load Cost Components	Unit	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25
A	Projected Default Service Volume	MWh	1,432	1,265	1,103	1,058	1,182	1,295
B	Total ISO Market Tranche Estimate	$ / MWh	$ 53.86	$ 46.23	$ 45.63	$ 60.95	$ 89.02	$ 116.37
C	Energy Price	$ / MWh	$ 45.66	$ 37.40	$ 36.01	$ 51.07	$ 79.81	$ 107.66
D	Capacity Price	$ / MWh	$ 4.77	$ 5.40	$ 6.20	$ 6.46	$ 5.79	$ 5.28
E	Net Commitment Period Compensation	$ / MWh	$ 0.94	$ 0.94	$ 0.94	$ 0.94	$ 0.94	$ 0.94
F	Ancillary Markets	$ / MWh	$ 1.76	$ 1.76	$ 1.76	$ 1.76	$ 1.76	$ 1.76
G	Misc Credit/Charge	$ / MWh	$ (0.32)	$ (0.32)	$ (0.32)	$ (0.32)	$ (0.32)	$ (0.32)
H	Wholesale Market Service Charge	$ / MWh	$ 1.05	$ 1.05	$ 1.05	$ 1.05	$ 1.05	$ 1.05

I	**Period Weighted Average Price**	**$ 69.03**

REDACTED

Unitil Energy Systems DE 24-065
Schedule JMP-6
Page 2 of 3

		Small Customer Group					
		2024					2025
		August	September	October	November	December	January
(1)	Peak Futures Pricing ($/MWh)	$54.50	$42.95	$39.45	$54.30	$83.65	$114.15
(2)	Off Peak Futures Pricing ($/MWh)	$34.55	$31.70	$32.05	$47.60	$76.25	$101.10
(3)	Monthly On Peak Load Percentage	56%	51%	54%	52%	48%	50%
(4)	Energy Price Estimate ($/MWh)	$ 45.66	$ 37.40	$ 36.01	$ 51.07	$ 79.81	$ 107.66

		Medium Customer Group					
		2024					2025
		August	September	October	November	December	January
(1)	Peak Futures Pricing ($/MWh)	$54.50	$42.95	$39.45	$54.30	$83.65	$114.15
(2)	Off Peak Futures Pricing ($/MWh)	$34.55	$31.70	$32.05	$47.60	$76.25	$101.10
(3)	Monthly On Peak Load Percentage	56%	51%	54%	52%	48%	50%
(4)	Energy Price Estimate ($/MWh)	$ 45.66	$ 37.40	$ 36.01	$ 51.07	$ 79.81	$ 107.66

(1) NYMEX Peak Prices for ISO-NE Hub as of 6/3/2024

(2) NYMEX Off Peak Prices for ISO-NE Hub as of 6/3/2024

(3) Company estimate, by month, or Residential Default Rate Class on peak load percentage

(4) Line (1) x Line (3) + Line (2) x (1 - Line (3))

Unitil Energy Systems DE 24-065
Schedule JMP-6
Page 3 of 3

		Small Customer Group					
		2024					2025
		August	September	October	November	December	January
(1)	Customer Capacity Load Obligation (MW)	154.453	154.453	154.453	154.453	154.453	154.453
(2)	Capacity Effective Charge Rate ($/mW-month)	2,347	2,347	2,348	2,348	2,350	2,350
(3)	Capacity Cost	$ 362,501.21	$ 362,501.21	$ 362,655.67	$ 362,655.67	$ 362,964.57	$ 362,964.57
(4)	Projected Default Service Volume (MWh)	41,985	34,676	28,000	27,709	35,360	41,427
(5)	Capacity Price Estimate ($/MWh)	$ 8.63	$ 10.45	$ 12.95	$ 13.09	$ 10.26	$ 8.76

		Medium Customer Group					
		2024					2025
		August	September	October	November	December	January
(1)	Customer Capacity Load Obligation (MW)	29.105	29.105	29.105	29.105	29.105	29.105
(2)	Capacity Effective Charge Rate ($/mW-month)	2,347	2,347	2,348	2,348	2,350	2,350
(3)	Capacity Cost	$ 68,309.26	$ 68,309.26	$ 68,338.36	$ 68,338.36	$ 68,396.57	$ 68,396.57
(4)	Projected Default Service Volume (MWh)	14,320	12,650	11,029	10,582	11,820	12,947
(5)	Capacity Price Estimate ($/MWh)	$ 4.77	$ 5.40	$ 6.20	$ 6.46	$ 5.79	$ 5.28

(1) Based on Company's estimate of NNE Customer Peak Contributions, Capacity Zonal Obligations and Capacity Zonal Peak Contributions
(2) ISO-NE Forward Capacity Market Cost Allocation Forecast as of 1/4/2023
(3) Line (1) x Line (2)
(4) Per Company Forecast
(5) Line (3) / Line (4)

REDACTED

Redacted

Unitil Energy Systems DE 24-065

Schedule JMP-7

Page 1 of 2

Table 1 - Total Power Supply Price Estimate - Small Customer Group

		Unit	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25
A	Evaluation Loads - 10% Tranche	MWh	4,198	3,468	2,800	2,771	3,536	4,143
B	Evaluation Loads - 90% Tranche	MWh	37,786	31,208	25,200	24,938	31,824	37,284
C	Evaluation Loads - Total	MWh	41,985	34,676	28,000	27,709	35,360	41,427
D*	Total ISO Market Tranche Estimate (10%)	$ / MWh	$ 57.72	$ 51.28	$ 52.39	$ 67.58	$ 93.50	$ 119.84
E	Fixed Price Contract (90%)	$ / MWh	[redacted]					
F	Total Wholesale Power Supply Rate Estimate	$ / MWh						

G	**Period Weighted Average Price**	[redacted]

* Table 1, Line B in Sch JMP-6

Table 1 - Total Power Supply Price Estimate - Medium Customer Group

		Unit	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25
A	Evaluation Loads - 10% Tranche	MWh	1,432	1,265	1,103	1,058	1,182	1,295
B	Evaluation Loads - 90% Tranche	MWh	12,888	11,385	9,926	9,524	10,638	11,652
C	Evaluation Loads - Total	MWh	14,320	12,650	11,029	10,582	11,820	12,947
D*	Total ISO Market Tranche Estimate (10%)	$ / MWh	$ 53.86	$ 46.23	$ 45.63	$ 60.95	$ 89.02	$ 116.37
E	Fixed Price Contract (90%)	$ / MWh	[redacted]					
F	Total Wholesale Power Supply Rate Estimate	$ / MWh						

G	**Period Weighted Average Price**	[redacted]

* Table 1, Line B in Sch JMP-6

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

LINDA S. MCNAMARA

New Hampshire Public Utilities Commission

Docket No. DE 24-065

June 7, 2024

TABLE OF CONTENTS

LIST OF SCHEDULES

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Linda S. McNamara. My business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. For whom do you work and in what capacity?

A. I am a Senior Regulatory Analyst for Unitil Service Corp. ("USC"), which provides centralized management and administrative services to all Unitil Corporation's affiliates including Unitil Energy Systems, Inc. ("UES").

Q. Please describe your business and educational background.

A. I joined USC in June 1994 after earning my Bachelor of Science Degree in Mathematics from the University of New Hampshire. Since that time, I have been responsible for the preparation of various regulatory filings, including changes to the default service charges, price analysis, and tariff changes.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present and explain the proposed changes to UES's Default Service Charge ("DSC") effective August 1, 2024 as reflected in the redline tariffs provided as Schedule LSM-1.

Q. Does the proposed DSC affect any tariff pages not included in Schedule LSM-1?

A. Yes. UES's Summary of Low-Income Electric Assistance Program Discounts, incorporating the proposed Non-G1 (Residential) DSC, and UES's Summary Of Whole House Residential Time Of Use Rates And Electric Vehicle Rates would also be affected by the change to the DSC. However, UES has proposed, and will propose, other August 1, 2024 rate changes that will also affect these pages. More specifically, on May 24, 2024, UES filed its proposed August 1, 2024 Revenue Decoupling Adjustment Factors. On approximately June 17, 2024, UES intends to file its External Delivery Charge ("EDC") and Stranded Cost Charge ("SCC") for effect August 1, 2024. Therefore, at this time, in order to avoid confusion regarding overlapping proposed versions, UES intends to file these proposed tariff pages as part of its EDC/SCC filing where it will incorporate all proposed August 1 rates.

Q. Has UES included tariff changes associated with NHPUC Order No. 26,973 where the Commission approved a modification to the solicitation process whereby the Company will include a self-supply market based tranche of 10% for Non-G1 customers?

A. Yes. In compliance with the directive in the Order, Schedule LSM-1 includes revisions to UES's Default Service, Schedule DS, tariff. The changes, provided in redline, are identical to those provided in response to discovery request DOE 1-4 Attachment 1 filed in DE 23-054.

III. RETAIL RATE CALCULATIONS

Q. What are the proposed Non-G1 Class DSC?

A. As shown on Schedule LSM-1, Page 1, the proposed Residential Class fixed Non-G1 DSC is $0.10506 per kWh and the proposed G2 and Outdoor Lighting ("OL") Class fixed Non-G1 DSC is $0.10027 per kWh for the period August 1, 2024 through January 31, 2025. The proposed Residential Class variable Non-G1 DSC and the proposed G2 and OL Class variable Non-G1 DSC for this same period are also shown on this page.

The proposed DSC are comprised of two components, as shown on Schedule LSM-1, Page 1: A Power Supply Charge and a Renewable Portfolio Standard ("RPS") Charge.

Q. What are the proposed Power Supply Charges and RPS Charge?

A. For the period August 1, 2024 through January 31, 2025, the proposed Residential Class fixed Non-G1 Power Supply Charge is $0.10334 per kWh, the proposed G2 and OL Class fixed Non-G1 Power Supply Charge is $0.09855 per kWh, and the proposed fixed Non-G1 RPS Charge is $0.00172 per kWh. These figures, as well as the variable amounts for the same period, are shown on Schedule LSM-1, Page 1.

Q. Have you compared how the proposed DSC rates compare to the current DSC and to the DSC effective last summer?

A. Yes, the table below provides a comparison of the fixed DSC, broken down by the Power Supply Charge and the RPS components, for these periods.

	Residential Class			G2 and OL Class		
	proposed 8/1/24	effective 2/1/24	effective 8/1/23	proposed 8/1/24	effective 2/1/24	effective 8/1/23
fixed Power Supply Charge	$0.10334	$0.10141	$0.12687	$0.09855	$0.09461	$0.12224
fixed RPS Charge	$0.00172	$0.00577	$0.00570	$0.00172	$0.00577	$0.00570
fixed DSC Charge ($/kWh)	$0.10506	$0.10718	$0.13257	$0.10027	$0.10038	$0.12794
% fixed Power Supply Charge to total	98.4%	94.6%	95.7%	98.3%	94.3%	95.5%
% fixed RPS Charge to total	1.6%	5.4%	4.3%	1.7%	5.7%	4.5%

Q. Please describe how the proposed Non-G1 fixed DSC rates compare to the Non-G1 fixed DSC rates in effect last summer.

A. The Residential Class fixed Non-G1 DSC in effect last summer, August 2023 through January 2024, was $0.13257 per kWh. The proposed Residential Class fixed Non-G1 DSC of $0.10506 per kWh is a decrease of $0.02751 per kWh.

The G2 and OL Class fixed Non-G1 DSC in effect last summer, August 2023 through January 2024, was $0.12794 per kWh. The proposed G2 and OL Class fixed Non-G1 DSC of $0.10027 per kWh is a decrease of $0.02767 per kWh.

Q. Please describe how the proposed Non-G1 fixed DSC rates compare to the current rate.

A. The proposed Residential Class fixed Non-G1 DSC of $0.10506 per kWh is a decrease of $0.00212 per kWh from the current DSC of $0.10718 per kWh. The proposed G2 and OL Class fixed Non-G1 DSC of $0.10027 per kWh is a decrease of $0.00011 per kWh from the current DSC of $0.10038 per kWh. These decreases are the result of the change in the RPS Charge for the period August 1, 2024 through January 31, 2025 compared to the current period February 1, 2024 through July 31, 2024.

Q. Please describe the calculation of the Non-G1 class DSC.

A. The rate calculations for the Non-G1 class Power Supply Charges, fixed and variable, are provided on Schedule LSM-2, Page 1. The rate calculations for the Non-G1 class RPS Charges, fixed and variable, are provided on Schedule LSM-3, Page 1. Both charges are calculated in a similar manner.

Variable pricing is calculated by dividing the total costs for the month, including a partial reconciliation of costs and revenues through April 30, 2024, by the estimated monthly kWh purchases for the Residential Class and the G2 and OL Class. An estimated loss factor of 6.4% is then added to arrive at the proposed retail variable charges. Fixed pricing is calculated in a similar manner, except that the calculation is based on each class's total for the entire six month period.

Q. Have you made any adjustments to the reconciliation balances included in the Power Supply and RPS charges?

A. In order to determine the reconciliation amount included in the Non-G1 class power supply charge, the reconciliation balance as of April 30, 2024 was adjusted to recognize that estimated revenue in May, June and July 2024 should exceed costs for this same period by an estimated $1,321,615. This adjustment recognizes that estimated costs for May, June and July 2024 are below the average cost for the entire rate period, February 2024-July 2024, while revenue will be primarily based on the fixed Power Supply Charge, of which most Non-G1 customers pay, and is determined using an average of costs for the entire February 2024-July 2024 period. This adjustment, provided on Schedule LSM-2, Page 1, brings the expected reconciliation balance from $1,977,418 to $656,397.

In order to determine the reconciliation amounts included in the Non-G1 class RPS, the reconciliation balance as of April 30, 2024 was adjusted to recognize that the current RPS charges, in effect through July 31, 2024, include a credit for the previous period's overcollection and to include an accounting adjustment related to Class III Renewable Energy Certificates (RECs). These adjustments are shown on Schedule LSM-3, Page 1.

Q. Please describe the accounting adjustment related to the Class III RECs in more detail.

A. As described in the testimony of Mr. Pentz, the Class III RPS obligation for the 2021 compliance year was initially set at 8% and therefore, UES began to purchase RECs under that requirement, procuring 14,500 RECs, or 2% of the assumed requirement. Because of the drop in the Class III requirement from 8% to 1%, for the 2021 compliance year, UES was only able to use part of the purchase to meet the 2021 compliance year and banked the remainder for use in the 2022 and/or 2023 compliance year. However, the full expense related to this procurement was recognized at the time of purchase. Upon review, UES determined that the expense should track with the use of the RECs and therefore, an adjustment to working capital and interest is required to recognize that part of the costs should have instead been included in 2023 (for the portion of the Class III RECS used for the 2022 compliance year) and 2024 (for the portion of the Class III RECs used in for the 2023 compliance year, plus the expired RECs). Adjusting the timing of these expenses results in a working capital and interest credit of $39,190 for the Non-G1 Class as shown on Schedule LSM-3, Page 1 of 5.

Since UES reconciles its costs on an annual basis, only a portion of the total reconciliation balances are reflected in the proposed Power Supply and RPS rates. UES apportioned the Power Supply balance and the RPS balance based on kWh over the twelve month period August 2024 through July 2025. The Power Supply reconciliation balance is further divided between the Residential Class and the

G2/OL Class, based on kWh. This calculation is provided on Page 1 of Schedule LSM-2 for Power Supply and Page 1 of Schedule LSM-3 for RPS.

Q. Have you provided details on the reconciliation?

A. Support for the April 30, 2024 Non-G1 class power supply reconciliation balance is provided on Schedule LSM-2, Page 2. Support for the April 30, 2024 Non-G1 class RPS reconciliation balance is provided on Schedule LSM-3, Page 2. As described above, those figures have been adjusted in order to arrive at the figures for collecton beginning August 1, 2024. Details for costs for the period May 2023 through April 2024 are provided on Page 3 of Schedule LSM-2 and LSM-3. Page 4 of Schedule LSM-2 and LSM-3 provides revenue details.

Q. Have you provided support for the total forecast costs shown on Page 1, lines 2 and 10 of Schedule LSM-2?

A. The details of forecasted costs for the period August 1, 2024 through January 31, 2025 are provided on Schedule LSM-2, Page 5. Line items for the various costs included in default service are shown and include: Non-G1 Class (Residential) DS Supplier and Market Charges, Non-G1 Class (G2 and OL) DS Supplier and Market Charges, GIS Support Payments, Supply Related Working Capital, Provision for Uncollected Accounts, Internal Company Administrative Costs, Legal Charges, Consulting Outside Service Charges, and the default service portion of the annual PUC Assessment allocated to the Non-G1 Class.

Q. Have you provided support for the total forecast costs shown on Page 1, line 2 of Schedule LSM-3?

A. The details of forecasted costs for the period August 1, 2024 through January 31, 2025 are provided on Schedule LSM-3, Page 5. Costs include RECs and the associated working capital.

Q. How is working capital calculated?

A. Working capital included in the Power Supply Charge equals the sum of working capital for Non-G1 Class (Residential) DS Supplier Charges, plus Non-G1 Class (G2 and OL) DS Supplier Charges[1], plus GIS Support Payments, as shown on Schedule LSM-2, Pages 3 and 5. It is calculated by taking the product of Non-G1 Class (Residential) DS Supplier Charges plus Non-G1 Class (G2 and OL) DS Supplier Charges plus GIS Support Payments and the number of days lag divided by 365 days (i.e. the working capital requirement) and multiplying it by the prime rate.

Beginning August 1, 2024, working capital included in the Power Supply Charge will also include working capital based on Non-G1 Class (Residential) DS Market Charges plus Non-G1 Class (G2 and OL) DS Market Charges. It

[1] In actuals, the supplier charges are provided in total in the column "Total Non-G1 Class DS Supplier Charges".

is calculated by taking the product of Non-G1 Class (Residential) DS Market Charges plus Non-G1 Class (G2 and OL) DS Market Charges and the number of days lag divided by 365 days (i.e. the working capital requirement) and multiplying it by the prime rate.

The calculation of working capital for RECs is included in the RPS Charge and is shown on Schedule LSM-3, Pages 3 and 5. It is calculated by taking the product of RECs and the number of days lead divided by 365 days (i.e. the working capital requirement) and multiplying it by the prime rate.

The calculation of working capital included in the Power Supply Charge and the RPS Charge for the period beginning August 1, 2024 rely on the results of the 2023 Default Service and Renewable Energy Credits Lead Lag Study, presented by Mr. Nawazelski. The Non-G1 class Power Supply Charge working capital calculation uses 21.82 days for the supplier charges/GIS component, and 48.28 days for the market charges. The Non-G1 class RPS Charge working capital calculation uses (293.00) days.

Q. Has UES calculated time differentiated DSC applicable to customers taking service under Schedule TOU-D, Schedule TOU-EV-D and Schedule TOU-EV-G2?

A. Yes, Schedule LSM-6, Page 1 of 1, provides time differentiated DSC based on the proposed August 1, 2024 Non-G1 class fixed DSC. The factors were calculated using the ratios established in DE 20-170 in order to determine the Off Peak, Mid Peak and On Peak rates for the residential and G2 TOU/EV classes. This schedule provides the rates for the remainder of the summer (August 1, 2024 through November 30, 2024) period as well as the rates that would be effective in December 2024 and January 2025. As noted earlier in my testimony, UES will include these rates in its Summary Of Whole House Residential Time Of Use Rates And Electric Vehicle Rates, tariff page 5-A, when filed.

Q. What is the proposed G1 Class DSC?

A. The proposed G1 class DSC are comprised of two components, as shown on Schedule LSM-1, Page 3: A Power Supply Charge and a Renewable Portfolio Standard ("RPS") Charge. The wholesale supplier charge included in the Power Supply Charge will be determined each month based on the sum of fixed monthly adders and variable energy prices, and therefore, the total DSC for the G1 class is not known at this time.

Q. What is the proposed Power Supply Charge, exclusive of supplier charges, and RPS Charge?

A. Schedule LSM-1, Page 3, shows the proposed G1 Power Supply Charges, excluding the supplier charge component, of $0.05707 per kWh in August 1, 2024 through January 31, 2025. The wholesale supply charge determined each month will be added to this amount to yield the monthly G1 class Power Supply Charge.

Also shown on Schedule LSM-1, Page 3, is the proposed G1 RPS Charge of ($0.00315) per kWh for August 1, 2024 through December 31, 2024, and and ($0.00282) per kWh in January 2025.

Q. Have you prepared a comparison of the proposed G1 DSC to the current rate?

A. No. As the total G1 class DSC is not yet known, a comparison to current rates was not performed.

Q. Please describe the calculation of the G1 class DSC.

A. The rate calculations for the Power Supply Charges, excluding wholesale supplier charges, are provided on Schedule LSM-4, Page 1. The rate calculations for the RPS Charges are provided on Schedule LSM-5, Page 1. Both charges are calculated in the same manner.

Each charge is calculated by dividing the costs for each month, including a partial reconciliation of costs and revenues through April 30, 2024, by the estimated G1 kWh purchases for the corresponding month. An estimated loss factor of 4.591% is then added to arrive at the proposed retail charges.

Similar to the Non-G1 power supply and RPS balances, the G1 class power supply and RPS reconciliation balances as of April 30, 2024 were adjusted in order to determine the reconcilation amount for this filing. Adjustments were made to reflect that the current DSC include reconciliation of the April 30, 2023 power supply and RPS balances, to incorporate the difference between the estimated supplier cost and revenue in May 2024, and similar to the Non-G1 Class RPS, to credit working capital and interest for $3,141 associated with the Class III RECs adjustment. These adjustments are shown on Page 1 of Schedule LSM-4 and LSM-5.

Q. Have you provided support for the total forecast costs shown on Page 1, line 2 of Schedule LSM-4?

A. The details of forecasted costs included in the Power Supply Charge for the period August 1, 2024 through January 31, 2025 are provided on Schedule LSM-4, Page 5. Line items for the various costs included in default service are shown and include: Total G1 Class DS Supplier Charges, GIS Support Payments, Supply Related Working Capital, Provision for Uncollected Accounts, Internal Company Administrative Costs, Legal Charges, Consulting Outside Service Charges, and the default service portion of the annual PUC Assessment allocated to the G1 Class. At the end of each month, UES will determine the supplier charge to be added to the monthly Power Supply Charge.

Q. Have you provided support for the total forecast costs shown on Page 1, line 2 of Schedule LSM-5?

A. The details of forecasted costs included in the RPS Charge for the period August 1, 2024 through January 31, 2025 are provided on Schedule LSM-5, Page 5. Costs include Renewable Energy Credits ("RECs") and the associated Working Capital.

Q. How is working capital calculated?

A. Working capital included in the Power Supply Charge equals the sum of working capital for Total G1 Class DS Supplier Charges plus GIS Support Payments and is shown on Schedule LSM-4, Pages 3 and 5. It is calculated by taking the product of Total G1 Class DS Supplier Charges plus GIS Support Payments and the number of days lag divided by 365 days (i.e. the working capital requirement) and multiplying it by the prime rate. As the Total G1 Class DS Supplier Charges for the upcoming rate period are not yet known, UES has estimated power supply costs for the purpose of estimating working capital. The estimate of power supply costs is based on the forecasted G1 class kWh purchases and an estimated price per kWh. The estimated price per kWh was determined by comparing a historical relationship between G1 and Non-G1 class supplier pricing and then applying that relationship to the current average Non-G1 supplier price per kWh. Actual working capital will be determined using the actual supplier charges in each month.

The calculation of working capital for RECs is included in the RPS Charge and is shown on Schedule LSM-5, Pages 3 and 5. It is calculated by taking the product of RECs and the number of days lead divided by 365 days (i.e. the working capital requirement) and multiplying it by the prime rate.

The calculation of working capital included in the Power Supply Charge and the RPS Charge, effective August 1, 2024, rely on the results of the 2023 Default Service and Renewable Energy Credits Lead Lag Study. The G1 class Power Supply Charge working capital calculation uses 4.34 days and the G1 class RPS Charge working capital calculation uses (310.56) days.

Q. Referring to Schedule LSM-6, why is the TOU-EV G1 class excluded?

A. The TOU-EV G1 class has been excluded from this schedule as their DSC is not time differentiated. The DSC included in UES's Summary Of Whole House Residential Time Of Use Rates And Electric Vehicle Rates, tariff page 5-A, is the same DSC applicable to all G1 customers.

IV. BILL IMPACTS

Q. Have you included any bill impacts associated with the proposed DSC rate changes?

A. Typical bill impacts for Non-G1 customers taking default service have been provided on Schedule LSM-7. Total bill impacts to G1 customers are unknown at this time and have therefore been excluded from Schedule LSM-7.

Pages 1 and 2 provide a table comparing the existing rates to the proposed rates for the residential and General Service rate classes. These pages also show the impact on a typical bill for each class in order to identify the effect of each rate component on a typical bill.

Page 3 shows bill impacts versus current rates to the residential class based on the mean and median use. Page 3 is provided in a format similar to Pages 1 and 2.

Page 4 provides the overall average class bill impacts as a result of changes to the DSC versus current rates. As shown, for customers on Default Service, the residential class will decrease by approximately 0.9%, general service will decrease by approximately 0.1%, and outdoor lighting will decrease by less than 0.1%.

Pages 5 through 10 of Schedule LSM-6 provide typical bill impacts versus current rates for all classes, excluding G1, for a range of usage levels.

Pages 11 and 12 provide a table comparing rates in effect in August 2023 to the proposed rates for the residential and General Service rate classes. These pages also show the impact on a typical bill for each class in order to identify the effect of each rate component on a typical bill. Residential customers taking fixed default service will see decreases of approximately 10.1% compared to last summer. G2 customers taking fixed default service will see decreases of roughly 11% compared to last summer. These decreases are due to the change in the Default Service Charge.

V. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.

CALCULATION OF THE DEFAULT SERVICE CHARGE

Non-G1 Class Default Service:

		Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Total
	Power Supply Charge							
	Residential Class							
1	Reconciliation	$49,890	$41,205	$33,272	$32,926	$42,018	$49,227	$248,539
2	Total Costs	$3,227,688	$2,361,843	$1,834,601	$2,208,834	$4,081,805	$6,350,072	$20,064,843
3	Reconciliation plus Total Costs (L.1 + L.2)	$3,277,578	$2,403,048	$1,867,873	$2,241,761	$4,123,823	$6,399,299	$20,313,382
4	kWh Purchases	41,984,987	34,676,020	28,000,055	27,709,113	35,360,008	41,427,106	209,157,288
5	Total, Before Losses (L.3 / L.4)	$0.07807	$0.06930	$0.06671	$0.08090	$0.11662	$0.15447	$0.09712
6	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
7	Total Retail Rate - Residential Variable Power Supply Charge (L.5 * (1+L.6))	$0.08306	$0.07374	$0.07098	$0.08608	$0.12409	$0.16436	
8	Total Retail Rate - Residential Fixed Power Supply Charge (L.5 * (1+L.6))							$0.10334
	G2 and OL Class							
9	Reconciliation	$17,013	$15,029	$13,104	$12,572	$14,043	$15,382	$87,143
10	Total Costs	$1,069,061	$829,033	$688,992	$822,624	$1,344,059	$1,952,638	$6,706,408
11	Reconciliation plus Total Costs (L.9 + L.10)	$1,086,075	$844,062	$702,096	$835,197	$1,358,102	$1,968,019	$6,793,551
12	kWh Purchases	14,320,059	12,649,985	11,029,215	10,581,999	11,820,080	12,946,794	73,348,132
13	Total, Before Losses (L.11 / L.12)	$0.07584	$0.06672	$0.06366	$0.07893	$0.11490	$0.15201	$0.09262
14	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
15	Total Retail Rate - G2 and OL Variable Power Supply Charge (L.13 * (1+L.14))	$0.08070	$0.07099	$0.06773	$0.08398	$0.12225	$0.16174	
16	Total Retail Rate - G2 and OL Fixed Power Supply Charge (L.13 * (1+L.14))							$0.09855

		Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Total
	Renewable Portfolio Standard (RPS) Charge							
17	Reconciliation	($370,222)	($311,182)	($256,629)	($251,775)	($310,223)	($357,524)	($1,857,555)
18	Total Costs	$457,807	$384,803	$317,346	$311,343	$383,612	$458,843	$2,313,755
19	Reconciliation plus Total Costs (L.17 + L.18)	$87,585	$73,621	$60,718	$59,568	$73,389	$101,319	$456,201
20	kWh Purchases	56,305,046	47,326,004	39,029,270	38,291,112	47,180,088	54,373,900	282,505,420
21	Total, Before Losses (L.19 / L.20)	$0.00156	$0.00156	$0.00156	$0.00156	$0.00156	$0.00186	$0.00161
22	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
23	Total Retail Rate - Variable RPS Charge (L.21 * (1+L.22))	$0.00166	$0.00166	$0.00166	$0.00166	$0.00166	$0.00198	
24	Total Retail Rate - Fixed RPS Charge (L.21 * (1+L.22))							$0.00172

		Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Total
	TOTAL DEFAULT SERVICE CHARGE							
25	**Total Retail Rate - Residential Variable Default Service Charge (L.7 + L.23)**	**$0.08472**	**$0.07540**	**$0.07264**	**$0.08774**	**$0.12575**	**$0.16634**	
26	**Total Retail Rate - Residential Fixed Default Service Charge (L.8+L.24)**							**$0.10506**
27	**Total Retail Rate - G2 and OL Variable Default Service Charge (L.15 + L.23)**	**$0.08236**	**$0.07265**	**$0.06939**	**$0.08564**	**$0.12391**	**$0.16372**	
28	**Total Retail Rate - G2 and OL Fixed Default Service Charge (L.16+L.24)**							**$0.10027**

Authorized by NHPUC Order No. ~~26,910~~ in Case No. DE 24-065 ~~23-054~~, dated ~~December 8, 2023~~

Issued: June 7, 2024 ~~December 19, 2023~~
Effective: August ~~February~~ 1, 2024

Issued By: Daniel Hurstak
~~Sr.~~ Vice President and Treasurer

CALCULATION OF THE DEFAULT SERVICE CHARGE

Non-G1 Class Default Service:

		Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Total
	Power Supply Charge							
	Residential Class							
1	Reconciliation	($17,345)	($16,162)	($13,775)	($12,559)	($14,468)	($18,388)	($92,697)
2	Total Costs	$5,917,807	$3,518,812	$2,430,232	$2,130,018	$2,533,205	$4,076,722	$20,606,795
3	Reconciliation plus Total Costs (L.1 + L.2)	$5,900,461	$3,502,650	$2,416,457	$2,117,459	$2,518,737	$4,058,334	$20,514,098
4	kWh Purchases	40,275,037	37,528,905	31,984,747	29,161,637	33,594,519	42,695,501	215,240,346
5	Total, Before Losses (L.3 / L.4)	$0.14650	$0.09333	$0.07555	$0.07261	$0.07497	$0.09505	$0.09531
6	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
7	Total Retail Rate - Residential Variable Power Supply Charge (L.5 * (1+L.6))	$0.15588	$0.09931	$0.08039	$0.07726	$0.07977	$0.10114	
8	Total Retail Rate - Residential Fixed Power Supply Charge (L.5 * (1+L.6))							$0.10141
	G2 and OL Class							
9	Reconciliation	($6,023)	($5,882)	($5,294)	($5,156)	($5,741)	($6,591)	($34,686)
10	Total Costs	$1,989,614	$1,230,582	$871,797	$813,446	$934,540	$1,356,592	$7,196,571
11	Reconciliation plus Total Costs (L.9 + L.10)	$1,983,592	$1,224,701	$866,503	$808,290	$928,798	$1,350,000	$7,161,884
12	kWh Purchases	13,985,282	13,657,550	12,292,516	11,972,691	13,332,417	15,305,606	80,546,062
13	Total, Before Losses (L.11 / L.12)	$0.14183	$0.08967	$0.07049	$0.06751	$0.06966	$0.08820	$0.08892
14	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
15	Total Retail Rate - G2 and OL Variable Power Supply Charge (L.13 * (1+L.14))	$0.15091	$0.09541	$0.07500	$0.07183	$0.07412	$0.09385	
16	Total Retail Rate - G2 and OL Fixed Power Supply Charge (L.13 * (1+L.14))							$0.09461

		Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Total
	Renewable Portfolio Standard (RPS) Charge							
17	Reconciliation	($142,564)	($134,488)	($116,334)	($108,077)	($123,296)	($152,393)	($777,152)
18	Total Costs	$437,016	$412,261	$356,617	$331,306	$377,959	$467,146	$2,382,304
19	Reconciliation plus Total Costs (L.17 + L.18)	$294,452	$277,773	$240,282	$223,229	$254,663	$314,754	$1,605,153
20	kWh Purchases	54,260,319	51,186,456	44,277,262	41,134,329	46,926,936	58,001,107	295,786,409
21	Total, Before Losses (L.19 / L.20)	$0.00543	$0.00543	$0.00543	$0.00543	$0.00543	$0.00543	$0.00543
22	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
23	Total Retail Rate - Variable RPS Charge (L.21 * (1+L.22))	$0.00577	$0.00577	$0.00577	$0.00577	$0.00577	$0.00577	
24	Total Retail Rate - Fixed RPS Charge (L.21 * (1+L.22))							$0.00577

		Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Total
	TOTAL DEFAULT SERVICE CHARGE							
25	**Total Retail Rate - Residential Variable Default Service Charge (L.7 + L.23)**	**$0.16165**	**$0.10508**	**$0.08616**	**$0.08303**	**$0.08554**	**$0.10691**	
26	**Total Retail Rate - Residential Fixed Default Service Charge (L.8+L.24)**							**$0.10718**
27	**Total Retail Rate - G2 and OL Variable Default Service Charge (L.15 + L.23)**	**$0.15668**	**$0.10118**	**$0.08077**	**$0.07760**	**$0.07989**	**$0.09962**	
28	**Total Retail Rate - G2 and OL Fixed Default Service Charge (L.16+L.24)**							**$0.10038**

CALCULATION OF THE DEFAULT SERVICE CHARGE

G1 Class Default Service:

		Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Total
	Power Supply Charge							
1	Reconciliation							*$375,829*
2	Total Costs excl. wholesale supplier charge							*$29,778*
3	Reconciliation plus Total Costs excl. wholesale supplier charge (L.1 + L.2)							*$405,607*
4	kWh Purchases							*7,433,835*
5	Total, Before Losses (L.3 / L.4)							*$0.05456*
6	Losses							*4.591%*
7	Power Supply Charge excl. wholesale supplier charge (L.5 * (1+L.6))	*$0.05707*	*$0.05707*	*$0.05707*	*$0.05707*	*$0.05707*	*$0.05707*	*$0.05707*
8a	Wholesale Supplier Charge	MARKET	MARKET	MARKET	MARKET	MARKET	MARKET	
8b	Losses	4.591%	4.591%	4.591%	4.591%	4.591%	4.591%	
8	Retail Rate - Wholesale Supplier Charge (L.8a * (1+L.8b))	MARKET	MARKET	MARKET	MARKET	MARKET	MARKET	
9	Total Retail Rate - Power Supply Charge (L.7 + L. 8)	MARKET	MARKET	MARKET	MARKET	MARKET	MARKET	

		Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Total
	Renewable Portfolio Standard (RPS) Charge							
10	Reconciliation	*($16,054)*	*($14,831)*	*($13,441)*	*($12,719)*	*($13,186)*	*($13,384)*	*($83,615)*
11	Total Costs	*$11,759*	*$10,864*	*$9,846*	*$9,316*	*$9,658*	*$10,175*	*$61,618*
12	Reconciliation plus Total Costs (L.10+ L.11)	*($4,295)*	*($3,968)*	*($3,596)*	*($3,402)*	*($3,527)*	*($3,209)*	*($21,997)*
13	kWh Purchases	*1,427,272*	*1,318,593*	*1,195,002*	*1,130,776*	*1,172,268*	*1,189,924*	*7,433,835*
14	Total, Before Losses (L.12 / L.13)	*($0.00301)*	*($0.00301)*	*($0.00301)*	*($0.00301)*	*($0.00301)*	*($0.00270)*	
15	Losses	*4.591%*	*4.591%*	*4.591%*	*4.591%*	*4.591%*	*4.591%*	
16	Total Retail Rate - RPS Charge (L.14 * (1+L.15))	*($0.00315)*	*($0.00315)*	*($0.00315)*	*($0.00315)*	*($0.00315)*	*($0.00282)*	

		Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Total
	TOTAL DEFAULT SERVICE CHARGE							
17	Total Retail Rate - Default Service Charge (L.9 + L.16)	**MARKET**	**MARKET**	**MARKET**	**MARKET**	**MARKET**	**MARKET**	

Authorized by NHPUC Order No. ~~26,910~~ in Case No. DE *24-065* ~~23-054~~, dated ~~December 8, 2023~~

~~NHPUC No. 3 - Electricity Delivery~~
~~Unitil Energy Systems, Inc.~~

~~CALCULATION OF THE DEFAULT SERVICE CHARGE~~

~~G1 Class Default Service:~~

		~~Feb-24~~	~~Mar-24~~	~~Apr-24~~	~~May-24~~	~~Jun-24~~	~~Jul-24~~	~~Total~~
	~~Power Supply Charge~~							
~~1~~	~~Reconciliation~~							~~$310,521~~
~~2~~	~~Total Costs excl. wholesale supplier charge~~							~~$30,622~~
~~3~~	~~Reconciliation plus Total Costs excl. wholesale supplier charge (L.1 + L.2)~~							~~$341,143~~
~~4~~	~~kWh Purchases~~							~~21,542,492~~
~~5~~	~~Total, Before Losses (L.3 / L.4)~~							~~$0.01584~~
~~6~~	~~Losses~~							~~4.591%~~
~~7~~	~~Power Supply Charge excl. wholesale supplier charge (L.5 * (1+L.6))~~	~~$0.01656~~	~~$0.01656~~	~~$0.01656~~	~~$0.01656~~	~~$0.01656~~	~~$0.01656~~	~~$0.01656~~
~~8a~~	~~Wholesale Supplier Charge~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	
~~8b~~	~~Losses~~	~~4.591%~~	~~4.591%~~	~~4.591%~~	~~4.591%~~	~~4.591%~~	~~4.591%~~	
~~8~~	~~Retail Rate - Wholesale Supplier Charge (L.8a * (1+L.8b))~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	
~~9~~	~~Total Retail Rate - Power Supply Charge (L.7 + L. 8)~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	

	~~Renewable Portfolio Standard (RPS) Charge~~							
~~10~~	~~Reconciliation~~	~~($5,290)~~	~~($5,141)~~	~~($5,019)~~	~~($5,009)~~	~~($5,557)~~	~~($6,110)~~	~~($32,125)~~
~~11~~	~~Total Costs~~	~~$29,033~~	~~$28,214~~	~~$27,546~~	~~$27,491~~	~~$30,496~~	~~$33,531~~	~~$176,312~~
~~12~~	~~Reconciliation plus Total Costs (L.10+ L.11)~~	~~$23,743~~	~~$23,073~~	~~$22,527~~	~~$22,482~~	~~$24,940~~	~~$27,422~~	~~$144,188~~
~~13~~	~~kWh Purchases~~	~~3,547,362~~	~~3,447,307~~	~~3,365,668~~	~~3,359,007~~	~~3,726,160~~	~~4,096,989~~	~~21,542,492~~
~~14~~	~~Total, Before Losses (L.12 / L.13)~~	~~$0.00669~~	~~$0.00669~~	~~$0.00669~~	~~$0.00669~~	~~$0.00669~~	~~$0.00669~~	
~~15~~	~~Losses~~	~~4.591%~~	~~4.591%~~	~~4.591%~~	~~4.591%~~	~~4.591%~~	~~4.591%~~	
~~16~~	~~Total Retail Rate - RPS Charge (L.14 * (1+L.15))~~	~~$0.00700~~	~~$0.00700~~	~~$0.00700~~	~~$0.00700~~	~~$0.00700~~	~~$0.00700~~	

	~~TOTAL DEFAULT SERVICE CHARGE~~						
~~17~~	~~Total Retail Rate - Default Service Charge (L.9 + L.16)~~	**~~MARKET~~**	**~~MARKET~~**	**~~MARKET~~**	**~~MARKET~~**	**~~MARKET~~**	**~~MARKET~~**

REDACTED

DEFAULT SERVICE
SCHEDULE DS

AVAILABILITY

This Schedule is for energy supply service only. Customers taking service hereunder must also take service under one of the Company's Delivery Service Schedules.

Default Service shall be available under this Schedule to all Customers, including Customers that return to utility-provided energy supply service after receiving energy supply service from a Competitive Supplier or self-supply (available to Market Participant End Users as described in NHPUC Order No. 24,172), or those Customers whose energy to be provided by a Competitive Supplier or self-supply does not reach the Company's distribution system for any reason.

CHARACTER OF SERVICE

Electricity will be supplied with the same characteristics as specified in the applicable Delivery Service Schedules.

DEFAULT SERVICE CHARGE

The Default Service Charges ("DSC") for each class are specified on Page 74 for the Non-G1 class and Page 75 for the G1 class, Calculation of the Default Service Charge.

DEFAULT SERVICE CHARGE RECONCILIATION

The DSC shall be calculated separately for the Non-G1 (all classes except G1) and the G1 classes. The DSC for each class shall consist of two separate components, a Power Supply Charge and a Renewable Portfolio Standard (RPS) charge. The Power Supply Charge will be comprised of GIS support payments, internal company administrative costs, supply-related working capital, external company legal and administrative costs, a provision for uncollectible accounts attributed to Default Service, and effective July 1, 2014, $10,000 per year associated with the NHPUC regulatory assessment, plus wholesale supplier and, for the Non-G1 class, direct market purchase charges. For the Non-G1 class, the Power Supply Charge shall be based on a forecast of all Power Supply costs, and shall include an annual reconciliation with interest for any over- or under-recoveries occurring in the prior period. The wholesale supplier and direct market purchase charge component of the Non-G1 class Power Supply Charge will be determined separately for Domestic (D) customers and for Regular General and Outdoor Lighting (G2, OL) customers. For the G1 class, the Power Supply Charge shall be based on wholesale supplier charges which will be determined at the end of each month, plus a forecast of all remaining Power Supply costs, and shall include an annual reconciliation with interest for any over- or under-recoveries occurring in the prior period.

The RPS Charge for each class shall be based on a forecast of the costs to comply with RPS and shall include an annual reconciliation with interest for any over- or under-recoveries occurring in the prior period.

Authorized by NHPUC Order No. ~~26,694~~ in Case No. DE ~~22-017~~ dated ~~September 30, 2022~~

Issued: ~~October 12, 2022~~June 7, 2024 Issued by: Daniel Hurstak ~~Robert B. Hevert~~

Effective: ~~December 1, 2022~~August 1, 2024 ~~Sr.~~ Vice President and Treasurer

DEFAULT SERVICE
SCHEDULE DS (continued)

~~Except for the DSC effective December 1, 2022, t~~The DSC for the Non-G1 class will be calculated on a six--month basis and shall be offered as a fixed charge or as a variable charge, as provided below. The G1 class DSC will also be established on a six--month basis, with the wholesale supplier charge component of the Power Supply Charge determined at the end of each month. The G1 class DSC shall be offered as a variable charge only, as provided below.~~ The DSC effective December 1, 2022 for the Non-G1 class and G1 class will be calculated on an eight month basis through July 31, 2023 and offered as a fixed charge or as a variable charge for the eight month period as well.~~

Separate reconciliation of costs and revenues for the Power Supply Charge and the RPS Charge, for both the Non-G1 and G1 classes, shall be performed on an annual basis effective June 1, 2022, and effective August 1, 2023 thereafter. For the Power Supply Charge, external company administrative costs will be directly assigned to the Non-G1 or G1 class, as applicable. Costs that are common to both classes will be allocated to those classes based on kWh sales. Costs of uncollectible accounts will be directly assigned to the Non-G1 or G1 class. Default Service costs included in the RPS Charge shall include costs of compliance with the Renewable Portfolio Standard and associated working capital.

Interest shall be calculated at the prime rate, with said prime rate to be fixed on a quarterly basis and to be established as reported in THE WALL STREET JOURNAL on the first business day of the month preceding the calendar quarter. If more than one rate is reported, the average of the reported rates shall be used. The Company may file to change the DSC at any time should significant over- or under-recoveries occur or be expected to occur.

Any adjustment to the DSC shall be in accordance with a notice filed with the Commission setting forth the amount of the proposed charge and the amount of the increase or decrease. The notice shall further specify the effective date of such charge, which shall not be earlier than forty-five days after the filing of the notice, or such other date as the Commission may authorize.

NON-G1 DEFAULT SERVICE CHARGES

Non-G1 Default Service pricing is available in two forms: fixed and variable. Fixed pricing will remain the same for six months~~[1]~~ at a time and will be based on the weighted average monthly wholesale price over the six-month~~[1]~~ period that the Company pays to its Default Service provider(s) and the forecasted cost of direct market purchases for the six-month period. Variable pricing will change from month to month reflecting the monthly wholesale price that the Company pays to its Default Service provider(s) and the monthly forecasted cost of direct market purchases.

Fixed pricing is available to all Non-G1 Customers except Non-G1 Customers who previously had a Competitive Supplier or self-supply and return to Default Service after the

~~[1] Except for the DSC effective December 1, 2022 through July 31, 2023 which will be based on eight months.~~

DEFAULT SERVICE
SCHEDULE DS (continued)

current six month~~[1]~~ rate period has commenced. New Non-G1 Customers and Non-G1 Customers receiving Default Service will automatically be placed on fixed pricing.

Variable pricing is available to new Non-G1 Customers, Non-G1 Customers who previously had a Competitive Supplier or self-supply and return to Default Service after the current six month~~[1]~~ rate period has commenced, and existing Non-G1 Customers who notify the Company of their intent to switch options at least two business days prior to the start of the six month~~[1]~~ rate period.

Non-G1 Customers returning to Default Service from a Competitive Supplier or self-supply during the rate period will automatically be placed on variable pricing. Non-G1 Customers electing variable pricing will not have the opportunity to switch back to fixed pricing until the subsequent six ~~-~~month~~[1]~~ rate period. Non-G1 Customers who were placed on variable pricing after returning from a Competitive Supplier or self-supply will be switched back to fixed pricing at the start of the subsequent six month~~[1]~~ period, unless notifying the Company at least two business days prior to the start of the subsequent six month~~[1]~~ period of their request to remain on variable pricing.

G1 DEFAULT SERVICE CHARGES

G1 Default Service pricing is available to all G1 customers as a variable charge only. The G1 Default Service Charge will change monthly, reflecting variations in the wholesale supply charges. The wholesale supply charges included in the Power Supply Charge will be determined as the sum of the average ISO-New England real time hourly locational marginal prices for the New Hampshire load zone, weighted by the wholesale hourly kWh volumes of the Company's G1 Default Service customers, and charges for capacity, ancillary services, and other supplier costs established through a competitive bidding process.

TERMS OF PAYMENT

The charges for service hereunder are net, billed monthly and due within 25 days following the date postmarked on the bill, as specified in the Terms and Conditions for Distribution Service, which is a part of this Tariff.

TERM OF CONTRACT

There is no specified term for service hereunder. Switching between optional energy supply services shall be in accordance with provisions contained in the schedules for such services.

DEFAULT SERVICE
SCHEDULE DS (continued)

SWITCHING TO A COMPETITIVE SUPPLIER OR SELF-SUPPLY

A. On Next Scheduled Meter Read Date

The Company will normally switch a Customer to a Competitive Supplier or self-supply upon request of a Customer as of the next scheduled meter read, provided that notice of the change to a Competitive Supplier or self-supply was received by the Company not less than two business days before that next scheduled meter read date. There shall be no charge for switching from Default Service to a Competitive Supplier or self-supply if such a notice is given.

B. Prior to the Next Scheduled Meter Read Date

If switching to a Competitive Supplier or self-supply before the next scheduled meter read is requested, the Company at its sole discretion and upon agreement by the Customer to pay the applicable fee pursuant to Section II. 10 of the Terms and Conditions for Distribution Service, will terminate Default Service with an unscheduled meter read.

TARIFF PROVISIONS

The Company's complete Tariff where not inconsistent with any specific provisions hereof, is part of this Schedule.

Unitil Energy Systems, Inc.
Calculation of Non-G1 Class Default Service Power Supply Charge

		Aug-24 Estimated	Sep-24 Estimated	Oct-24 Estimated	Nov-24 Estimated	Dec-24 Estimated	Jan-25 Estimated	Total
	Residential Class							
1	Reconciliation (1)	$49,890	$41,205	$33,272	$32,926	$42,018	$49,227	$248,539
2	Total Costs (Page 5)	$3,227,688	$2,361,843	$1,834,601	$2,208,834	$4,081,805	$6,350,072	$20,064,843
3	Reconciliation plus Total Costs (L.1 + L.2)	$3,277,578	$2,403,048	$1,867,873	$2,241,761	$4,123,823	$6,399,299	$20,313,382
4	kWh Purchases	41,984,987	34,676,020	28,000,055	27,709,113	35,360,008	41,427,106	209,157,288
5	Total, Before Losses (L.3 / L.4)	$0.07807	$0.06930	$0.06671	$0.08090	$0.11662	$0.15447	$0.09712
6	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
7	Total Retail Rate - Residential Variable Power Supply Charge (L.5 * (1+L.6))	$0.08306	$0.07374	$0.07098	$0.08608	$0.12409	$0.16436	
8	Total Retail Rate - Residential Fixed Power Supply Charge (L.5 * (1+L.6))							$0.10334
	G2 and OL Class							
9	Reconciliation (1)	$17,013	$15,029	$13,104	$12,572	$14,043	$15,382	$87,143
10	Total Costs (Page 5)	$1,069,061	$829,033	$688,992	$822,624	$1,344,059	$1,952,638	$6,706,408
11	Reconciliation plus Total Costs (L.9 + L.10)	$1,086,075	$844,062	$702,096	$835,197	$1,358,102	$1,968,019	$6,793,551
12	kWh Purchases	14,320,059	12,649,985	11,029,215	10,581,999	11,820,080	12,946,794	73,348,132
13	Total, Before Losses (L.11 / L.12)	$0.07584	$0.06672	$0.06366	$0.07893	$0.11490	$0.15201	$0.09262
14	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
15	Total Retail Rate - G2 and OL Variable Power Supply Charge (L.13 * (1+L.14))	$0.08070	$0.07099	$0.06773	$0.08398	$0.12225	$0.16174	
16	Total Retail Rate - G2 and OL Fixed Power Supply Charge (L.13 * (1+L.14))							$0.09855

(1) Balance as of April 30, 2024 modified, as detailed below, to include the reconciliation of estimated costs and revenues for May, June and July 2024. Figure is then allocated between rate periods (August 2024-January2025 and February-July 2025) and rate classes (Residential and G2/OL), and then to each month, August 2024 through January 2025, on equal per kWh basis.

a	April 30, 2024 balance - Schedule LSM-2, Page 2	$1,977,418
b	less: Estimated remaining prior period reconciliation - May, Jun, Jul 2024:	
c	Estimated costs - May, Jun, Jul 2024	$11,844,522
d	Estimated revenue- May, Jun, Jul 2024	$13,165,543
e	line c - line d	($1,321,021)
f	Reconciliation for August 1, 2024-July 31, 2025 (line a + line e)	$656,397

		Non-G1 total kWh purchases	% per period	Reconciliation per period
g	Rate period: August 2024-January 2025	282,505,420	51.14%	$335,681
h	Rate period: February-July 2025	269,860,691	48.86%	$320,716
i	Total	552,366,112		$656,397

		Aug2024-Jan2025 kWh purchases	% by class	Aug2024-Jan2025 Reconciliation by class
j	Residential class	209,157,288	74.04%	$248,539
k	G2 and OL class	73,348,132	25.96%	$87,143
l	Total	282,505,420		$335,681

REDACTED

Unitil Energy Systems, Inc.
Reconciliation of Non-G1 Class Power Supply Charge Costs and Revenues

	(a) Beginning Balance	(b) Total Costs (Page 3)	(c) Total Revenue (Page 4)	(d) Ending Balance Before Interest (a + b - c)	(e) Average Monthly Balance ((a+d) / 2)	(f) Interest Rate	(g) Number of Days / Month	(h) Computed Interest	(i) Ending Balance with Interest (d + h)
May-23	$14,222,310	$5,441,992	$9,356,694	$10,307,607	$12,264,959	7.75%	31	$80,730	$10,388,338
Jun-23	$10,388,338	$4,950,660	$9,147,306	$6,191,692	$8,290,015	7.75%	30	$52,806	$6,244,498
Jul-23	$6,244,498	$8,233,650	$13,948,391	$529,756	$3,387,127	8.25%	31	$23,733	$553,489
Aug-23	$553,489	$3,775,178	$4,997,905	($669,238)	($57,874)	8.25%	31	($406)	($669,643)
Sep-23	($669,643)	$2,582,263	$4,739,779	($2,827,160)	($1,748,401)	8.25%	30	($11,856)	($2,839,015)
Oct-23	($2,839,015)	$1,793,055	$4,594,483	($5,640,443)	($4,239,729)	8.50%	31	($30,607)	($5,671,051)
Nov-23	($5,671,051)	$3,511,078	$4,758,354	($6,918,327)	($6,294,689)	8.50%	30	($43,977)	($6,962,303)
Dec-23	($6,962,303)	$7,973,783	$5,260,462	($4,248,982)	($5,605,643)	8.50%	31	($40,468)	($4,289,450)
Jan-24	($4,289,450)	$11,497,691	$6,422,181	$786,060	($1,751,695)	8.50%	31	($12,611)	$773,449
Feb-24	$773,449	$6,134,226	$4,052,699	$2,854,976	$1,814,212	8.50%	29	$12,219	$2,867,194
Mar-24	$2,867,194	$3,772,756	$4,177,574	$2,462,376	$2,664,785	8.50%	31	$19,185	$2,481,561
Apr-24	$2,481,561	$2,582,210	$3,101,833	$1,961,939	$2,221,750	8.50%	30	$15,479	$1,977,418
Total		$62,248,541	$74,557,661					$64,228	

Unitil Energy Systems, Inc.
Itemized Costs for Non-G1 Class Default Service Charge

			Calculation of Working Capital Supplier Charges and GIS Support Payments										
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Total Non-G1 Class DS Supplier Charges	GIS Support Payments	Number of Days of Lag / 365 (1)	Working Capital Requirement ((a+b)*c)	Prime Rate (2)	Supply Related Working Capital (d * e)	Provision for Uncollected Accounts	Internal Company Administrative Costs	Legal Charges	Consulting Outside Service Charges	Default Service Portion of the annual PUC Assessment	Total Costs (sum a + b + f + g + h + i + j + k)
May-23	$5,373,691	$487	6.17%	$331,579	8.23%	$27,289	$36,855	$2,912	$0	$0	$758	$5,441,992
Jun-23	$4,875,459	$473	6.17%	$300,838	8.25%	$24,819	$46,249	$2,912	$0	$0	$749	$4,950,660
Jul-23	$8,149,296	$503	6.17%	$502,831	8.29%	$41,685	$38,496	$2,912	$0	$0	$758	$8,233,650
Aug-23	$3,637,195	$489	4.74%	$172,416	8.50%	$14,655	$119,116	$2,912	$0	$0	$810	$3,775,178
Sep-23	$2,472,268	$499	4.74%	$117,202	8.50%	$9,962	$94,998	$2,912	$814	$0	$809	$2,582,263
Oct-23	$1,693,278	$443	4.74%	$80,278	8.50%	$6,824	$88,794	$2,912	$0	$0	$804	$1,793,055
Nov-23	$3,426,202	$432	4.74%	$162,413	8.50%	$13,805	$66,919	$2,912	$0	$0	$808	$3,511,078
Dec-23	$7,881,755	$420	4.74%	$373,594	8.50%	$31,755	$56,129	$2,912	$0	$0	$812	$7,973,783
Jan-24	$11,360,678	$443	4.74%	$538,486	8.50%	$45,771	$87,074	$2,912	$0	$0	$813	$11,497,691
Feb-24	$6,050,645	$465	4.74%	$286,806	8.50%	$24,379	$54,837	$3,088	$0	$0	$813	$6,134,226
Mar-24	$3,680,653	$473	4.74%	$174,475	8.50%	$14,830	$72,903	$3,088	$0	$0	$809	$3,772,756
Apr-24	$2,547,512	$457	4.74%	$120,767	8.50%	$10,265	$20,082	$3,088	$0	$0	$807	$2,582,210
Total	$61,148,632	$5,584				$266,040	$782,450	$35,471	$814	$0	$9,550	$62,248,541

(1) For the months May-July 2023, number of days lag equals 22.52. Calculated using revenue lag of 58.28 days less cost lead of 35.76 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 22 of 23, DE 22-017 filed March, 25, 2022.

For the months August 2023-April 2024, number of days lag equals 17.30. Calculated using revenue lag of 56.39 days less cost lead of 39.09 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 22 of 23, DE 23-054 filed June 9, 2023.

(2) Per Order 25,028 in DG 07-072 "The carrying charge for cash working capital related to electric supply costs shall remain at the prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and fixed on a monthly basis, consistent with Commission Order No. 24,682 in the Unitil Energy Systems Docket DE 06-123".

Unitil Energy Systems, Inc.
Non-G1 Class Default Service Power Supply Charge Revenue

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Total Residential Class Billed Default Service kWh (1)	Unbilled Factor (2)	Residential Class Unbilled kWh (a * b)	Effective Fixed Power Supply Charge	Residential Class Unbilled Power Supply Charge Revenue (c * d)	Total G2/OL Class Billed Default Service kWh (1)	Unbilled Factor (2)	G2/OL Class Unbilled kWh (f * g)	Effective Fixed Power Supply Charge	G2/OL Class Unbilled Power Supply Charge Revenue (h * i)	Reversal of prior month unbilled	Total Billed Non-G1 Class Power Supply Charge Revenue (1)	Total Revenue (e + j + k + l)
May-23	27,910,687	46.0%	12,826,302	$0.25397	$3,257,496	10,917,875	46.0%	5,017,288	$0.24847	$1,246,646	($4,687,604)	$9,540,157	$9,356,694
Jun-23	26,032,885	52.6%	13,702,202	$0.25397	$3,479,948	10,076,924	52.6%	5,303,909	$0.24847	$1,317,862	($4,504,142)	$8,853,638	$9,147,306
Jul-23	37,881,324	49.5%	18,735,235	$0.25397	$4,758,188	12,656,473	49.5%	6,259,602	$0.24847	$1,555,323	($4,797,810)	$12,432,691	$13,948,391
Aug-23	37,756,048	39.0%	14,721,051	$0.12687	$1,867,660	11,836,720	39.0%	4,615,127	$0.12224	$564,153	($6,313,511)	$8,879,603	$4,997,905
Sep-23	32,797,987	33.6%	11,010,229	$0.12687	$1,396,868	10,710,852	33.6%	3,595,615	$0.12224	$439,528	($2,431,813)	$5,335,196	$4,739,779
Oct-23	25,977,219	48.0%	12,474,020	$0.12687	$1,582,579	9,356,754	48.0%	4,493,027	$0.12224	$549,228	($1,836,396)	$4,299,072	$4,594,483
Nov-23	25,893,136	60.7%	15,729,528	$0.12687	$1,995,605	8,696,834	60.7%	5,283,141	$0.12224	$645,811	($2,131,807)	$4,248,744	$4,758,354
Dec-23	30,750,843	54.7%	16,807,093	$0.12687	$2,132,316	9,671,189	54.7%	5,285,857	$0.12224	$646,143	($2,641,416)	$5,123,420	$5,260,462
Jan-24	34,063,440	60.3%	20,542,270	$0.12687	$2,606,198	10,410,615	60.3%	6,278,217	$0.12224	$767,449	($2,778,459)	$5,826,993	$6,422,181
Feb-24	35,887,009	38.5%	13,814,520	$0.10141	$1,400,930	11,452,913	38.5%	4,408,740	$0.09461	$417,111	($3,373,647)	$5,608,304	$4,052,699
Mar-24	30,652,881	45.8%	14,034,257	$0.10141	$1,423,214	10,253,982	45.8%	4,694,730	$0.09461	$444,168	($1,818,041)	$4,128,233	$4,177,574
Apr-24	25,207,028	47.2%	11,891,614	$0.10141	$1,205,929	8,837,026	47.2%	4,168,937	$0.09461	$394,423	($1,867,382)	$3,368,864	$3,101,833
Total	370,810,487				$27,106,930	124,878,157				$8,987,846	($39,182,028)	$77,644,914	$74,557,661

(1) Per billing system
(2) Detail of Unbilled Factors for the Residential, Regular General, and Outdoor Lighting Classes:

	Non-G1 Class Billed kWh	Direct Estimate of Unbilled kWh	Unbilled kWh / Billed kWh
May-23	57,291,455	26,328,178	46.0%
Jun-23	59,141,441	31,128,626	52.6%
Jul-23	81,049,716	40,085,333	49.5%
Aug-23	80,799,741	31,503,750	39.0%
Sep-23	71,923,515	24,144,604	33.6%
Oct-23	60,055,995	28,838,333	48.0%
Nov-23	58,666,878	35,638,878	60.7%
Dec-23	66,657,723	36,432,255	54.7%
Jan-24	72,768,272	43,883,573	60.3%
Feb-24	77,454,626	29,815,760	38.5%
Mar-24	67,526,719	30,916,745	45.8%
Apr-24	60,278,909	28,437,051	47.2%

REDACTED

Redacted

Unitil Energy Systems, Inc.
Itemized Costs for Non-G1 Class Default Service Charge

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	Subtotals (m)	(n)	(o)
	Non-G1 Class (Residential) DS Supplier Charges (1)	Non-G1 Class (G2 and OL) DS Supplier Charges (1)	Non-G1 Class (Residential) DS Market Charges (1)	Non-G1 Class (G2 and OL) DS Market Charges (1)	GIS Support Payments	Total Supply Related Working Capital (2)	Provision for Uncollected Accounts	Internal Company Administrative Costs	Legal Charges	Consulting Outside Service Charges	Default Service Portion of the annual PUC Assessment	Total All Costs (sum col. (a) thru (k))	Total Residential DS Supplier & Market Charges (col. (a) + (c))	G2 and OL DS Supplier & Market Charges (col. (b) + (d))	Total Remaining Costs (sum col. (e) thru (k))
Aug-24	[redacted]	[redacted]	$242,336	$77,122	$424	[redacted]	[redacted]	$3,088	$0	$0	$812	$4,296,749	[redacted]	[redacted]	[redacted]
Sep-24	[redacted]	[redacted]	$177,817	$58,475	$478	[redacted]	[redacted]	$3,088	$0	$0	$812	$3,190,876	[redacted]	[redacted]	[redacted]
Oct-24	[redacted]	[redacted]	$146,679	$50,326	$648	[redacted]	[redacted]	$3,088	$0	$0	$812	$2,523,594	[redacted]	[redacted]	[redacted]
Nov-24	[redacted]	[redacted]	$187,251	$64,495	$655	[redacted]	[redacted]	$3,088	$0	$0	$812	$3,031,459	[redacted]	[redacted]	[redacted]
Dec-24	[redacted]	[redacted]	$330,608	$105,222	$487	[redacted]	[redacted]	$3,088	$0	$0	$812	$5,425,864	[redacted]	[redacted]	[redacted]
Jan-25	[redacted]	[redacted]	$496,478	$150,656	$452	[redacted]	[redacted]	$3,088	$0	$0	$812	$8,302,709	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	$1,581,169	$506,294	$3,143	[redacted]	[redacted]	$18,527	$0	$0	$4,870	$26,771,251	[redacted]	[redacted]	[redacted]

Total Costs Associated with the Residential Class

	Non-G1 Class (Residential) DS Supplier & Market Charges (col. (m))	Allocation of Remaining Costs (col. (o)) to Residential Class (3)	Total Non-G1 Class (Residential) Power Supply Charges
	(i)	(ii)	(iii) = (i) + (ii)
Aug-24	[redacted]	[redacted]	$3,227,688
Sep-24	[redacted]	[redacted]	$2,361,843
Oct-24	[redacted]	[redacted]	$1,834,601
Nov-24	[redacted]	[redacted]	$2,208,834
Dec-24	[redacted]	[redacted]	$4,081,805
Jan-25	[redacted]	[redacted]	$6,350,072
Total	[redacted]	[redacted]	$20,064,843

Total Costs Associated with the G2/OL Class

	Non-G1 Class (G2 and OL) DS Supplier & Market Charges (col. (n))	Allocation of Remaining Costs (col. (o)) to G2 and OL Class (3)	Total Non-G1 Class (G2 and OL) Power Supply Charges
	(iv)	(v)	(vi) = (iv) + (v)
Aug-24	[redacted]	[redacted]	$1,069,061
Sep-24	[redacted]	[redacted]	$829,033
Oct-24	[redacted]	[redacted]	$688,992
Nov-24	[redacted]	[redacted]	$822,624
Dec-24	[redacted]	[redacted]	$1,344,059
Jan-25	[redacted]	[redacted]	$1,952,638
Total	[redacted]	[redacted]	$6,706,408

(1) Estimates based on monthly wholesale rate times estimated monthly purchases.
(2) Calculation of Supply Related Working Capital:

	(i)	(ii)	(iii)	(iv)	(v)	(vi)	(vii)	(viii)	(ix)	(x)	(xi)	(xii)	(xiii)
	Total Non-G1 Class DS Supplier Charges (col. (a) + (b))	GIS Costs (col. (e))	Total	Number of Days of Lag / 365 (4)	Working Capital Requirement (iii * iv)	Prime Rate (5)	Supply Related Working Capital-Supplier Charges (v * vi)	Total Non-G1 Class DS Market Charges (col. (c) + (d))	Number of Days of Lag / 365 (6)	Working Capital Requirement (viii * ix)	Prime Rate (5)	Supply Related Working Capital-Market Charges (x * xi)	Total Supply Related Working Capital (sum (vii) and (xii))
Aug-24	[redacted]	$424	[redacted]	5.98%	[redacted]	8.50%	[redacted]	$319,457	13.23%	$42,256	8.50%	$3,592	[redacted]
Sep-24	[redacted]	$478	[redacted]	5.98%	[redacted]	8.50%	[redacted]	$236,292	13.23%	$31,255	8.50%	$2,657	[redacted]
Oct-24	[redacted]	$648	[redacted]	5.98%	[redacted]	8.50%	[redacted]	$197,005	13.23%	$26,059	8.50%	$2,215	[redacted]
Nov-24	[redacted]	$655	[redacted]	5.98%	[redacted]	8.50%	[redacted]	$251,746	13.23%	$33,299	8.50%	$2,830	[redacted]
Dec-24	[redacted]	$487	[redacted]	5.98%	[redacted]	8.50%	[redacted]	$435,830	13.23%	$57,649	8.50%	$4,900	[redacted]
Jan-25	[redacted]	$452	[redacted]	5.98%	[redacted]	8.50%	[redacted]	$647,134	13.23%	$85,599	8.50%	$7,276	[redacted]
Total	[redacted]	$3,143	[redacted]				[redacted]	$2,087,464				$23,470	[redacted]

(3) Remaining Costs (column o) allocated between the Residential Class and the G2 and Outdoor Lighting Class based on estimated monthly kWh purchases, as shown below:

	Estimated kWh Purchases - Residential Class	Estimated kWh Purchases - G2 and OL Class	Total Non-G1 Class kWh Purchases	Residential Class kWh Purchases / Total Non-G1 Class kWh	G2 and OL Class kWh Purchases / Total Non-G1 Class kWh
Aug-24	41,984,987	14,320,059	56,305,046	74.6%	25.4%
Sep-24	34,676,020	12,649,985	47,326,004	73.3%	26.7%
Oct-24	28,000,055	11,029,215	39,029,270	71.7%	28.3%
Nov-24	27,709,113	10,581,999	38,291,112	72.4%	27.6%
Dec-24	35,360,008	11,820,080	47,180,088	74.9%	25.1%
Jan-25	41,427,106	12,946,794	54,373,900	76.2%	23.8%
Total	209,157,288	73,348,132	282,505,420		

(4) Number of days lag equals 21.82. Calculated using revenue lag of 56.83 days less cost lead of 35.01 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 22 of 23, DE 24-065 filed June 7, 2024.
(5) Per Order 25,028 in DG 07-072 "The carrying charge for cash working capital related to electric supply costs shall remain at the prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and fixed on a monthly basis, consistent with Commission Order No. 24,682 in the Unitil Energy Systems Docket DE 06-123".
(6) Number of days lag equals 48.28. Calculated using revenue lag of 56.83 days less cost lead of 8.55 days. Revenue lag and cost lead per Schedule DTN-3, DE 24-065 filed June 7, 2024.

Unitil Energy Systems, Inc.
Calculation of Non-G1 Class Default Service Renewable Portfolio Standard (RPS) Charge

		Aug-24 Estimated	Sep-24 Estimated	Oct-24 Estimated	Nov-24 Estimated	Dec-24 Estimated	Jan-25 Estimated	Total
1	Reconciliation (1)	($370,222)	($311,182)	($256,629)	($251,775)	($310,223)	($357,524)	($1,857,555)
2	Total Costs (Page 5)	$457,807	$384,803	$317,346	$311,343	$383,612	$458,843	$2,313,755
3	Reconciliation plus Total Costs (L.1 + L.2)	$87,585	$73,621	$60,718	$59,568	$73,389	$101,319	$456,201
4	kWh Purchases	56,305,046	47,326,004	39,029,270	38,291,112	47,180,088	54,373,900	282,505,420
5	Total, Before Losses (L.3 / L.4)	$0.00156	$0.00156	$0.00156	$0.00156	$0.00156	$0.00186	$0.00161
6	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
7	Total Retail Rate - Variable RPS Charge (L.5 * (1+L.6))	$0.00166	$0.00166	$0.00166	$0.00166	$0.00166	$0.00198	
8	Total Retail Rate - Fixed RPS Charge (L.5 * (1+L.6))							$0.00172

(1) Balance as of April 30, 2024 modified, as detailed below, to reflect that current rates include a reconciliation through July 31, 2024. Figure is then allocated between rate periods (August 2024-January 2025 and February-July 2025) and then to each month, August 2024 through January 2025, on equal per kWh basis.

a	April 30, 2024 actual balance - Schedule LSM-3, Page 2			($3,977,477)
b	plus: adjustment to working capital and interest associated with accounting of RECs			($39,190)
c	less: Estimated remaining prior period reconciliation - May, Jun, Jul 2024:			
d	Estimated kWh Sales May-Jul 2024			137,276,665
e	Amount of reconciliation in current RPS Charge			($0.00280)
f	Estimated amount of reconciliation - May-Jul 2024			($384,375)
g	Total reconciliation for August 1, 2024-July 31, 2025 (line a + line b - line f)			($3,632,293)
		Non-G1 total kWh purchases	% per period	Reconciliation per period
h	Rate period: August 2024-January 2025	282,505,420	51.14%	($1,857,555)
i	Rate period: February-July 2025	269,860,691	48.86%	($1,774,738)
j	Total	552,366,112		($3,632,293)

Unitil Energy Systems, Inc.
Reconciliation of Non-G1 Class RPS Costs and Revenues

	(a) Beginning Balance	(b) Total Costs (Page 3)	(c) Total Revenue (Page 4)	(d) Ending Balance Before Interest (a + b - c)	(e) Average Monthly Balance ((a+d) / 2)	(f) Interest Rate	(g) Number of Days / Month	(h) Computed Interest	(i) Ending Balance with Interest (d + h)
May-23	($1,947,974)	$406,055	$201,273	($1,743,192)	($1,845,583)	7.75%	31	($12,148)	($1,755,340)
Jun-23	($1,755,340)	($1,218,009)	$196,845	($3,170,194)	($2,462,767)	7.75%	30	($15,687)	($3,185,882)
Jul-23	($3,185,882)	$417,242	$298,529	($3,067,168)	($3,126,525)	8.25%	31	($21,907)	($3,089,075)
Aug-23	($3,089,075)	$416,068	$251,461	($2,924,469)	($3,006,772)	8.25%	31	($21,068)	($2,945,537)
Sep-23	($2,945,537)	$118,267	$220,880	($3,048,149)	($2,996,843)	8.25%	30	($20,321)	($3,068,471)
Oct-23	($3,068,471)	$382,979	$214,732	($2,900,224)	($2,984,347)	8.50%	31	($21,545)	($2,921,768)
Nov-23	($2,921,768)	$382,979	$220,097	($2,758,886)	($2,840,327)	8.50%	30	($19,843)	($2,778,729)
Dec-23	($2,778,729)	($64,111)	$236,424	($3,079,264)	($2,928,997)	8.50%	31	($21,145)	($3,100,409)
Jan-24	($3,100,409)	$420,831	$280,726	($2,960,305)	($3,030,357)	8.50%	31	($21,817)	($2,982,122)
Feb-24	($2,982,122)	$420,831	$224,082	($2,785,373)	($2,883,748)	8.50%	29	($19,422)	($2,804,795)
Mar-24	($2,804,795)	($1,084,885)	$238,956	($4,128,636)	($3,466,716)	8.50%	31	($24,958)	($4,153,595)
Apr-24	($4,153,595)	$385,386	$181,041	($3,949,250)	($4,051,423)	8.50%	30	($28,227)	($3,977,477)
Total		$983,633	$2,765,048					($248,089)	

Unitil Energy Systems, Inc.
Itemized Costs for Non-G1 Class Default Service Renewable Portfolio Standard Charge

	Renewable Energy Credits	Number of Days of Lag / 365 (1)	Working Capital Requirement (a*b)	Prime Rate (2)	Supply Related Working Capital (c * d)	Total Costs (sum a + e)
May-23	$430,316	(68.51%)	($294,796)	8.23%	($24,262)	$406,055
Jun-23	($1,290,972)	(68.51%)	$884,404	8.25%	$72,963	($1,218,009)
Jul-23	$442,365	(68.51%)	($303,051)	8.29%	($25,123)	$417,242
Aug-23	$442,365	(69.94%)	($309,377)	8.50%	($26,297)	$416,068
Sep-23	$125,742	(69.94%)	($87,940)	8.50%	($7,475)	$118,267
Oct-23	$407,185	(69.94%)	($284,773)	8.50%	($24,206)	$382,979
Nov-23	$407,185	(69.94%)	($284,773)	8.50%	($24,206)	$382,979
Dec-23	($68,163)	(69.94%)	$47,671	8.50%	$4,052	($64,111)
Jan-24	$447,429	(69.94%)	($312,918)	8.50%	($26,598)	$420,831
Feb-24	$447,429	(69.94%)	($312,918)	8.50%	($26,598)	$420,831
Mar-24	($1,153,453)	(69.94%)	$806,691	8.50%	$68,569	($1,084,885)
Apr-24	$409,743	(69.94%)	($286,562)	8.50%	($24,358)	$385,386
Total	$1,047,171				($63,538)	$983,633

(1) For the months May-July 2023, number of days lag equals (250.05). Calculated using revenue lag of 58.28 days less cost lead of 308.33 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 22 of 23, DE 22-017 filed March 25, 2022.

For the months August 2023-April 2024, number of days lag equals (255.27). Calculated using revenue lag of 56.39 days less cost lead of 311.66 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 22 of 23, DE 23-054 filed June 9, 2023.

(2) Per Order 25,028 in DG 07-072 "The carrying charge for cash working capital related to electric supply costs shall remain at the prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and fixed on a monthly basis, consistent with Commission Order No. 24,682 in the Unitil Energy Systems Docket DE 06-123".

Unitil Energy Systems, Inc.
Non-G1 Class Default Service Renewable Portfolio Standard Charge Revenue

	(a) Total Non-G1 Class Billed Default Service kWh (1)	(b) Unbilled Factor (2)	(c) Non-G1 Class Unbilled kWh (a * b)	(d) Effective Fixed RPS Charge	(e) Non-G1 Class Unbilled RPS Charge Revenue (c * d)	(f) Reversal of prior month unbilled	(g) Total Billed Non-G1 Class RPS Charge Revenue (1)	(h) Total Revenue (e + f + g)
May-23	38,828,562	46.0%	17,843,591	$0.00528	$94,214	($98,037)	$205,096	$201,273
Jun-23	36,109,809	52.6%	19,006,110	$0.00528	$100,352	($94,214)	$190,707	$196,845
Jul-23	50,537,797	49.5%	24,994,837	$0.00528	$131,973	($100,352)	$266,909	$298,529
Aug-23	49,592,768	39.0%	19,336,178	$0.00570	$110,216	($131,973)	$273,218	$251,461
Sep-23	43,508,839	33.6%	14,605,845	$0.00570	$83,253	($110,216)	$247,842	$220,880
Oct-23	35,333,973	48.0%	16,967,047	$0.00570	$96,712	($83,253)	$201,273	$214,732
Nov-23	34,589,970	60.7%	21,012,669	$0.00570	$119,772	($96,712)	$197,037	$220,097
Dec-23	40,422,032	54.7%	22,092,950	$0.00570	$125,930	($119,772)	$230,267	$236,424
Jan-24	44,474,055	60.3%	26,820,486	$0.00570	$152,877	($125,930)	$253,779	$280,726
Feb-24	47,339,922	38.5%	18,223,260	$0.00577	$105,148	($152,877)	$271,811	$224,082
Mar-24	40,906,863	45.8%	18,728,987	$0.00577	$108,066	($105,148)	$236,038	$238,956
Apr-24	34,044,054	47.2%	16,060,551	$0.00577	$92,669	($108,066)	$196,438	$181,041
Total	495,688,644				$1,321,184	($1,326,551)	$2,770,416	$2,765,048

(1) Per billing system
(2) Detail of Unbilled Factors for the Residential, Regular General, and Outdoor Lighting Classes:

	Billed kWh	Direct Estimate of Unbilled kWh	Unbilled kWh / Billed kWh
May-23	57,291,455	26,328,178	46.0%
Jun-23	59,141,441	31,128,626	52.6%
Jul-23	81,049,716	40,085,333	49.5%
Aug-23	80,799,741	31,503,750	39.0%
Sep-23	71,923,515	24,144,604	33.6%
Oct-23	60,055,995	28,838,333	48.0%
Nov-23	58,666,878	35,638,878	60.7%
Dec-23	66,657,723	36,432,255	54.7%
Jan-24	72,768,272	43,883,573	60.3%
Feb-24	77,454,626	29,815,760	38.5%
Mar-24	67,526,719	30,916,745	45.8%
Apr-24	60,278,909	28,437,051	47.2%

Unitil Energy Systems, Inc.
Itemized Costs for Non-G1 Class Default Service Renewable Portfolio Standard Charge

Schedule LSM-3
Page 5 of 5

		Calculation of Working Capital				
	(a)	(b)	(c)	(d)	(e)	(f)
	Renewable Energy Credits (1)	Number of Days of Lag / 365 (2)	Working Capital Requirement (a*b)	Prime Rate (3)	Supply Related Working Capital (c * d)	Total Costs (sum a + e)
Aug-24	$491,332	(80.27%)	($394,412)	8.50%	($33,525)	$457,807
Sep-24	$412,982	(80.27%)	($331,517)	8.50%	($28,179)	$384,803
Oct-24	$340,586	(80.27%)	($273,402)	8.50%	($23,239)	$317,346
Nov-24	$334,143	(80.27%)	($268,230)	8.50%	($22,800)	$311,343
Dec-24	$411,704	(80.27%)	($330,491)	8.50%	($28,092)	$383,612
Jan-25	$492,444	(80.27%)	($395,305)	8.50%	($33,601)	$458,843
Total	$2,483,190		($1,993,356)		($169,435)	$2,313,755

(1) Schedule JMP-4.

(2) Number of days lag equals (293.00). Calculated using revenue lag of 56.83 days less cost lead of 349.83 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 22 of 23, DE 24-065 filed June 7, 2024.

(3) Per Order 25,028 in DG 07-072 "The carrying charge for cash working capital related to electric supply costs shall remain at the prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and fixed on a monthly basis, consistent with Commission Order No. 24,682 in the Unitil Energy Systems Docket DE 06-123".

Unitil Energy Systems, Inc.
Calculation of G1 Large General Service Class Default Service Power Supply Charge

		Total Aug 2024-Jan 2025
1	Reconciliation (1)	$375,829
2	Total Costs excl. wholesale supplier charge (Page 5)	$29,778
3	Reconciliation plus Total Costs excl. wholesale supplier charge (L.1 + L.2)	$405,607
4	kWh Purchases	7,433,835
5	Total, Before Losses (L.3 / L.4)	$0.05456
6	Losses	4.591%
7	Power Supply Charge excl. wholesale supplier charge (L.5 * (1+L.6)) (2)	$0.05707

(1) Balance as of April 30, 2024 modified, as detailed below, to reflect that current rates include a reconciliation through July 31, 2024 and to incorporate the difference between the estimated supplier cost and revenue in May 2024. Figure is then allocated between rate periods (August 2024-January 2025 and February-July 2025) and then to each month, August 2024 through January 2025, on equal per kWh basis.

a	April 30, 2024 actual balance - Schedule LSM-4, Page 2		$798,357	
b	less: Estimated remaining prior period reconciliation - May, Jun, Jul 2024:			
c		Estimated kWh Sales May-Jul 2024	4,137,603	
d		Amount of reconciliation in current rate	$0.01508	
e		Estimated amount of reconciliation - May-Jul 2024	$62,395	
f	plus: Difference between the estimated supplier cost and revenue for May 2024		$2,691	
g	Total reconciliation for August 1, 2024-July 31, 2025 (line a - line e + line f)		$738,653	
h	kWh purchases forecast August 2024-January 2025		7,433,835	50.88%
i	kWh purchases forecast February-July 2025		7,176,609	49.12%
j	Total		14,610,443	
k	Reconciliation amount for August 2024-January 2025	(line g * line h%)	$375,829	
l	Reconciliation amount for February-July 2025	(line g * line i%)	$362,824	
m	Total	(line k + line l)	$738,653	

(2) The total G1 Power Supply Charge will equal the sum of Line 7 plus a wholesale supplier charge which shall be determined at the end of each month. The wholesale supply charges will be determined as the sum of the average ISO-New England real time hourly locational marginal prices for the New Hampshire load zone, weighted by the wholesale hourly kWh volumes of the Company's G1 Default Service customers, and charges for capacity, ancillary services, and other supplier costs established through a competitive bidding process.

Unitil Energy Systems, Inc.
Reconciliation of G1 Class Power Supply Charge Costs and Revenues

	(a) Beginning Balance	(b) Total Costs (Page 3)	(c) Total Revenue (Page 4)	(d) Ending Balance Before Interest (a + b - c)	(e) Average Monthly Balance ((a+d) / 2)	(f) Interest Rate	(g) Number of Days / Month	(h) Computed Interest	(i) Ending Balance with Interest (d + h)
May-23	$611,641	$277,764	$279,938	$609,468	$610,555	7.75%	31	$4,019	$613,487
Jun-23	$613,487	$333,869	$257,962	$689,394	$651,440	7.75%	30	$4,150	$693,543
Jul-23	$693,543	$393,670	$346,887	$740,326	$716,935	8.25%	31	$5,023	$745,350
Aug-23	$745,350	$193,002	$28,563	$909,789	$827,569	8.25%	31	$5,799	$915,587
Sep-23	$915,587	$112,029	$101,284	$926,333	$920,960	8.25%	30	$6,245	$932,577
Oct-23	$932,577	$68,975	$99,261	$902,291	$917,434	8.50%	31	$6,623	$908,915
Nov-23	$908,915	$102,706	$73,147	$938,473	$923,694	8.50%	30	$6,453	$944,927
Dec-23	$944,927	$41,866	$84,967	$901,825	$923,376	8.50%	31	$6,666	$908,491
Jan-24	$908,491	$75,558	$116,555	$867,495	$887,993	8.50%	31	$6,393	$873,888
Feb-24	$873,888	$86,157	$121,638	$838,407	$856,147	8.50%	29	$5,766	$844,173
Mar-24	$844,173	$69,629	$105,516	$808,286	$826,229	8.50%	31	$5,948	$814,234
Apr-24	$814,234	$52,626	$74,101	$792,759	$803,496	8.50%	30	$5,598	$798,357
Total		$1,807,853	$1,689,821					$68,683	

Redacted

Unitil Energy Systems, Inc.
Itemized Costs for G1 Class Default Service Power Supply Charge

Schedule LSM-4
Page 3 of 5

Calculation of Working Capital

	Supplier Charges and GIS Support Payments											
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Total G1 Class DS Supplier Charges	GIS Support Payments	Number of Days of Lag / 365 (1)	Working Capital Requirement	Prime Rate (2)	Supply Related Working Capital (d * e)	Provision for Uncollected Accounts	Internal Company Administrative Costs	Legal Charges	Consulting Outside Service Charges	Default Service Portion of the annual PUC Assessment	Total Costs (sum a + b + f + g + h + i + j + k)
May-23	[redacted]	$48	1.15%	[redacted]	8.23%	[redacted]	[redacted]	$4,530	$0	$0	$75	$277,764
Jun-23	[redacted]	$53	1.15%	[redacted]	8.25%	[redacted]	[redacted]	$4,530	$0	$0	$85	$333,869
Jul-23	[redacted]	$50	1.15%	[redacted]	8.29%	[redacted]	[redacted]	$4,530	$0	$0	$75	$393,670
Aug-23	[redacted]	$14	0.96%	[redacted]	8.50%	[redacted]	[redacted]	$4,530	$0	$0	$24	$193,002
Sep-23	[redacted]	$15	0.96%	[redacted]	8.50%	[redacted]	[redacted]	$4,530	$25	$0	$25	$112,029
Oct-23	[redacted]	$16	0.96%	[redacted]	8.50%	[redacted]	[redacted]	$4,530	$0	$0	$29	$68,975
Nov-23	[redacted]	$14	0.96%	[redacted]	8.50%	[redacted]	[redacted]	$4,530	$0	$0	$25	$102,706
Dec-23	[redacted]	$11	0.96%	[redacted]	8.50%	[redacted]	[redacted]	$4,530	$0	$0	$21	$41,866
Jan-24	[redacted]	$11	0.96%	[redacted]	8.50%	[redacted]	[redacted]	$4,530	$0	$0	$21	$75,558
Feb-24	[redacted]	$12	0.96%	[redacted]	8.50%	[redacted]	[redacted]	$4,816	$0	$0	$21	$86,157
Mar-24	[redacted]	$14	0.96%	[redacted]	8.50%	[redacted]	[redacted]	$4,816	$0	$0	$24	$69,629
Apr-24	[redacted]	$15	0.96%	[redacted]	8.50%	[redacted]	[redacted]	$4,816	$0	$0	$26	$52,626
Total	[redacted]	$273		[redacted]		[redacted]	[redacted]	$55,216	$25	$0	$450	$1,807,853

(1) For the months May-July 2023, number of days lag equals 4.20. Calculated using revenue lag of 43.25 days less cost lead of 39.05 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 20 of 23, DE 22-017 filed March 25, 2022.

For the months August 2023-April 2024, number of days lag equals 3.51. Calculated using revenue lag of 42.67 days less cost lead of 39.16 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 20 of 23, DE 23-054 filed June 9, 2023.

(2) Per Order 25,028 in DG 07-072 "The carrying charge for cash working capital related to electric supply costs shall remain at the prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and fixed on a monthly basis, consistent with Commission Order No. 24,682 in the Unitil Energy Systems Docket DE 06-123".

Unitil Energy Systems, Inc.
G1 Class Default Service Power Supply Charge Revenue

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Total G1 Class Billed Default Service kWh (1)	Unbilled Factor (2)	G1 Class Unbilled kWh (a * b)	Effective Variable Power Supply Charge	G1 Class Unbilled Power Supply Charge Revenue (c * d)	Reversal of prior month unbilled	Total Billed G1 Class Power Supply Charge Revenue (1)	Total Revenue (e + f + g)
May-23	3,860,865	46.0%	1,774,147	$0.07218	$128,058	($161,969)	$313,849	$279,938
Jun-23	4,077,781	45.3%	1,847,937	$0.06245	$115,404	($128,058)	$270,616	$257,962
Jul-23	5,024,132	43.6%	2,188,904	$0.06467	$141,556	($115,404)	$320,735	$346,887
Aug-23	1,445,174	45.0%	649,790	$0.08947	$58,137	($141,556)	$111,983	$28,563
Sep-23	1,320,359	49.4%	652,085	$0.07627	$49,734	($58,137)	$109,686	$101,284
Oct-23	1,269,034	48.0%	609,318	$0.08091	$49,300	($49,734)	$99,696	$99,261
Nov-23	1,086,434	55.1%	598,662	$0.06852	$41,020	($49,300)	$81,427	$73,147
Dec-23	1,048,519	55.1%	577,302	$0.08222	$47,466	($41,020)	$78,522	$84,967
Jan-24	1,122,798	56.3%	632,474	$0.09949	$62,925	($47,466)	$101,096	$116,555
Feb-24	1,209,794	40.0%	484,218	$0.11501	$55,690	($62,925)	$128,873	$121,638
Mar-24	1,214,774	45.9%	557,841	$0.07938	$44,281	($55,690)	$116,925	$105,516
Apr-24	1,094,727	50.4%	551,476	$0.06813	$37,572	($44,281)	$80,811	$74,101
Total	23,774,391				$831,144	($955,540)	$1,814,218	$1,689,821

(1) Per billing system
(2) Detail of Unbilled Factors for the Large General Class:

	Billed kWh	Direct Estimate of Unbilled kWh	Unbilled kWh / Billed kWh
May-23	25,479,468	11,708,344	46.0%
Jun-23	26,519,028	12,017,686	45.3%
Jul-23	30,217,311	13,165,020	43.6%
Aug-23	29,874,700	13,432,486	45.0%
Sep-23	28,416,899	14,034,231	49.4%
Oct-23	26,548,036	12,746,860	48.0%
Nov-23	24,572,113	13,540,076	55.1%
Dec-23	24,103,509	13,271,108	55.1%
Jan-24	24,107,407	13,579,740	56.3%
Feb-24	27,291,151	10,923,245	40.0%
Mar-24	25,094,654	11,523,804	45.9%
Apr-24	23,994,855	12,087,572	50.4%

Unitil Energy Systems, Inc.
Itemized Costs for G1 Class Default Service Power Supply Charge

			Calculation of Working Capital Supplier Charges and GIS Support Payments									
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Total G1 Class DS Supplier Charges (1)	GIS Support Payments	Number of Days of Lag / 365 (2)	Working Capital Requirement (3)	Prime Rate (4)	Supply Related Working Capital (d * e)	Provision for Uncollected Accounts	Internal Company Administrative Costs	Legal Charges	Consulting Outside Service Charges	Default Service Portion of the annual PUC Assessment	Total Costs (sum a + b + f + g + h + i + j + k)
Aug-24		$58	1.19%	$948	8.50%	$81	$0	$4,816	$0	$0	$22	$4,976
Sep-24		$50	1.19%	$769	8.50%	$65	$0	$4,816	$0	$0	$22	$4,952
Oct-24		$39	1.19%	$663	8.50%	$56	$0	$4,816	$0	$0	$22	$4,933
Nov-24		$38	1.19%	$775	8.50%	$66	$0	$4,816	$0	$0	$22	$4,941
Dec-24		$33	1.19%	$1,179	8.50%	$100	$0	$4,816	$0	$0	$22	$4,971
Jan-25		$31	1.19%	$1,594	8.50%	$135	$0	$4,816	$0	$0	$22	$5,004
Total		$250				$504	$0	$28,894	$0	$0	$131	$29,778

(1) DS Supplier Charges to be determined at the end of each month.

(2) Number of days lag equals 4.34. Calculated using revenue lag of 38.39 days less cost lead of 34.05 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 20 of 23, DE 24-065 filed June 7, 2024.

(3) The working capital requirement equals the supplier charge plus GIS Support payment times the number of days lag divided by 365. As the G1 class supplier charge is not determined using a contract price, estimates of the G1 class power supply costs were calculated based on the forecasted G1 class kWh purchases and an estimated price per kWh. The estimated price per kWh was determined by comparing a historical relationship between G1 and Non-G1 class supplier pricing and then applying that relationship to the current average Non-G1 supplier price per kWh. Actual working capital will be determined using the actual supplier charges in each month.

(4) Per Order 25,028 in DG 07-072 "The carrying charge for cash working capital related to electric supply costs shall remain at the prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and fixed on a monthly basis, consistent with Commission Order No. 24,682 in the Unitil Energy Systems Docket DE 06-123".

REDACTED

Unitil Energy Systems, Inc.
Calculation of G1 Class Default Service Renewable Portfolio Standard (RPS) Charge

		Aug-24 Estimated	Sep-24 Estimated	Oct-24 Estimated	Nov-24 Estimated	Dec-24 Estimated	Jan-25 Estimated	Total
1	Reconciliation (1)	($16,054)	($14,831)	($13,441)	($12,719)	($13,186)	($13,384)	($83,615)
2	Total Costs (Page 5)	$11,759	$10,864	$9,846	$9,316	$9,658	$10,175	$61,618
3	Reconciliation plus Total Costs (L.1 + L.2)	($4,295)	($3,968)	($3,596)	($3,402)	($3,527)	($3,209)	($21,997)
4	kWh Purchases	1,427,272	1,318,593	1,195,002	1,130,776	1,172,268	1,189,924	7,433,835
5	Total, Before Losses (L.3 / L.4)	($0.00301)	($0.00301)	($0.00301)	($0.00301)	($0.00301)	($0.00270)	
6	Losses	4.591%	4.591%	4.591%	4.591%	4.591%	4.591%	
7	Total Retail Rate - Variable RPS Charge (L.5 * (1+L.6))	($0.00315)	($0.00315)	($0.00315)	($0.00315)	($0.00315)	($0.00282)	

(1) Balance as of April 30, 2024 modified, as detailed below, to reflect that current rates include a reconciliation through July 31, 2024. Figure is then allocated between rate periods (August 2024-January 2025 and February-July 2025) and then to each month, August 2024 through January 2025, on equal per kWh basis.

a	April 30, 2024 actual balance - Schedule LSM-5, Page 2	($167,652)
b	plus: adjustment to working capital and interest associated with accounting of RECs	($3,141)
c	less: Estimated remaining prior period reconciliation - May, Jun, Jul 2024:	
d	Estimated kWh Sales May-Jul 2024	4,137,603
e	Amount of reconciliation in current rate	($0.00156)
f	Estimated amount of reconciliation - May-Jul 2024	($6,455)
g	Total reconciliation for August 1, 2024-July 31, 2025 (line a + line b - line f)	($164,338)

		G1 kWh purchases	% per period	Reconciliation per period
h	Rate period: August 2024-January 2025	7,433,835	50.88%	($83,615)
i	Rate period: February-July 2025	7,176,609	49.12%	($80,723)
j	Total	14,610,443		($164,338)

Unitil Energy Systems, Inc.
Reconciliation of G1 Class RPS Costs and Revenues

Schedule LSM-5
Page 2 of 5

	(a) Beginning Balance	(b) Total Costs (Page 3)	(c) Total Revenue (Page 4)	(d) Ending Balance Before Interest (a + b - c)	(e) Average Monthly Balance ((a+d) / 2)	(f) Interest Rate	(g) Number of Days / Month	(h) Computed Interest	(i) Ending Balance with Interest (d + h)
May-23	($95,177)	$34,933	$21,584	($81,828)	($88,503)	7.75%	31	($583)	($82,410)
Jun-23	($82,410)	($104,786)	$22,751	($209,947)	($146,179)	7.75%	30	($931)	($210,878)
Jul-23	($210,878)	$34,720	$29,401	($205,559)	($208,219)	8.25%	31	($1,459)	($207,018)
Aug-23	($207,018)	$34,656	$1,413	($173,776)	($190,397)	8.25%	31	($1,334)	($175,110)
Sep-23	($175,110)	$9,851	$9,073	($174,332)	($174,721)	8.25%	30	($1,185)	($175,517)
Oct-23	($175,517)	$31,900	$8,412	($152,029)	($163,773)	8.50%	31	($1,182)	($153,211)
Nov-23	($153,211)	$31,900	$7,380	($128,691)	($140,951)	8.50%	30	($985)	($129,676)
Dec-23	($129,676)	($5,340)	$7,046	($142,062)	($135,869)	8.50%	31	($981)	($143,043)
Jan-24	($143,043)	$35,053	$8,457	($116,448)	($129,746)	8.50%	31	($934)	($117,382)
Feb-24	($117,382)	$35,053	$7,436	($89,766)	($103,574)	8.50%	29	($698)	($90,463)
Mar-24	($90,463)	($90,398)	$9,019	($189,879)	($140,171)	8.50%	31	($1,009)	($190,889)
Apr-24	($190,889)	$32,100	$7,619	($166,407)	($178,648)	8.50%	30	($1,245)	($167,652)
Total		$79,642	$139,591					($12,525)	

REDACTED

Unitil Energy Systems, Inc.
Itemized Costs for G1 Class Default Service Renewable Portfolio Standard Charge

		Calculation of Working Capital				
	(a)	(b)	(c)	(d)	(e)	(f)
	Renewable Energy Credits	Number of Days of Lag / 365 (1)	Working Capital Requirement (a*b)	Prime Rate (2)	Supply Related Working Capital (c * d)	Total Costs (sum a + e)
May-23	$37,114	(71.39%)	($26,495)	8.23%	($2,181)	$34,933
Jun-23	($111,344)	(71.39%)	$79,487	8.25%	$6,558	($104,786)
Jul-23	$36,904	(71.39%)	($26,345)	8.29%	($2,184)	$34,720
Aug-23	$36,904	(71.65%)	($26,443)	8.50%	($2,248)	$34,656
Sep-23	$10,490	(71.65%)	($7,517)	8.50%	($639)	$9,851
Oct-23	$33,969	(71.65%)	($24,340)	8.50%	($2,069)	$31,900
Nov-23	$33,969	(71.65%)	($24,340)	8.50%	($2,069)	$31,900
Dec-23	($5,686)	(71.65%)	$4,075	8.50%	$346	($5,340)
Jan-24	$37,326	(71.65%)	($26,746)	8.50%	($2,273)	$35,053
Feb-24	$37,326	(71.65%)	($26,746)	8.50%	($2,273)	$35,053
Mar-24	($96,261)	(71.65%)	$68,975	8.50%	$5,863	($90,398)
Apr-24	$34,182	(71.65%)	($24,493)	8.50%	($2,082)	$32,100
Total	$84,893				($5,251)	$79,642

(1) For the months May-July 2023, number of days lag equals (260.57). Calculated using revenue lag of 43.25 days less cost lead of 303.82 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 20 of 23, DE 22-017 filed March 25, 2022.

For the months August 2023-April 2024, number of days lag equals (261.54). Calculated using revenue lag of 42.67 days less cost lead of 304.21 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 20 of 23, DE 23-054 filed June 9, 2023.

(2) Per Order 25,028 in DG 07-072 "The carrying charge for cash working capital related to electric supply costs shall remain at the prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and fixed on a monthly basis, consistent with Commission Order No. 24,682 in the Unitil Energy Systems Docket DE 06-123".

Unitil Energy Systems, Inc.
G1 Class Default Service Renewable Portfolio Standard Charge Revenue

	(a) Total G1 Class Billed Default Service kWh (1)	(b) Unbilled Factor (2)	(c) G1 Class Unbilled kWh (a * b)	(d) Effective Variable RPS Charge	(e) G1 Class Unbilled RPS Charge Revenue (c * d)	(f) Reversal of prior month unbilled	(g) Total Billed G1 Class RPS Charge Revenue (1)	(h) Total Revenue (e + f + g)
May-23	3,860,865	46.0%	1,774,147	$0.00548	$9,722	($9,296)	$21,158	$21,584
Jun-23	4,077,781	45.3%	1,847,937	$0.00548	$10,127	($9,722)	$22,346	$22,751
Jul-23	5,024,132	43.6%	2,188,904	$0.00548	$11,995	($10,127)	$27,532	$29,401
Aug-23	1,445,174	45.0%	649,790	$0.00686	$4,458	($11,995)	$8,951	$1,413
Sep-23	1,320,359	49.4%	652,085	$0.00686	$4,473	($4,458)	$9,058	$9,073
Oct-23	1,269,034	48.0%	609,318	$0.00686	$4,180	($4,473)	$8,706	$8,412
Nov-23	1,086,434	55.1%	598,662	$0.00686	$4,107	($4,180)	$7,453	$7,380
Dec-23	1,048,519	55.1%	577,302	$0.00686	$3,960	($4,107)	$7,193	$7,046
Jan-24	1,122,798	56.3%	632,474	$0.00719	$4,547	($3,960)	$7,870	$8,457
Feb-24	1,209,794	40.0%	484,218	$0.00700	$3,390	($4,547)	$8,594	$7,436
Mar-24	1,214,774	45.9%	557,841	$0.00700	$3,905	($3,390)	$8,503	$9,019
Apr-24	1,094,727	50.4%	551,476	$0.00700	$3,860	($3,905)	$7,663	$7,619
Total	23,774,391				$68,724	($74,160)	$145,027	$139,591

(1) Per billing system
(2) Detail of Unbilled Factors for the Large General Class:

	Billed kWh	Direct Estimate of Unbilled kWh	Unbilled kWh / Billed kWh
May-23	25,479,468	11,708,344	46.0%
Jun-23	26,519,028	12,017,686	45.3%
Jul-23	30,217,311	13,165,020	43.6%
Aug-23	29,874,700	13,432,486	45.0%
Sep-23	28,416,899	14,034,231	49.4%
Oct-23	26,548,036	12,746,860	48.0%
Nov-23	24,572,113	13,540,076	55.1%
Dec-23	24,103,509	13,271,108	55.1%
Jan-24	24,107,407	13,579,740	56.3%
Feb-24	27,291,151	10,923,245	40.0%
Mar-24	25,094,654	11,523,804	45.9%
Apr-24	23,994,855	12,087,572	50.4%

REDACTED

Unitil Energy Systems, Inc.
Itemized Costs for G1 Class Default Service Renewable Portfolio Standard Charge

		Calculation of Working Capital				
	(a)	(b)	(c)	(d)	(e)	(f)
	Renewable Energy Credits (1)	Number of Days of Lag / 365 (2)	Working Capital Requirement (a*b)	Prime Rate (3)	Supply Related Working Capital (c * d)	Total Costs (sum a + e)
Aug-24	$12,676	(85.08%)	($10,785)	8.50%	($917)	$11,759
Sep-24	$11,711	(85.08%)	($9,964)	8.50%	($847)	$10,864
Oct-24	$10,613	(85.08%)	($9,030)	8.50%	($768)	$9,846
Nov-24	$10,043	(85.08%)	($8,545)	8.50%	($726)	$9,316
Dec-24	$10,411	(85.08%)	($8,858)	8.50%	($753)	$9,658
Jan-25	$10,968	(85.08%)	($9,332)	8.50%	($793)	$10,175
Total	$66,422				($4,804)	$61,618

(1) Schedule JMP-4.

(2) Number of days lag equals (310.56). Calculated using revenue lag of 38.39 days less cost lead of 348.95 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 20 of 23, DE 24-065 filed June 7, 2024.

(3) Per Order 25,028 in DG 07-072 "The carrying charge for cash working capital related to electric supply costs shall remain at the prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and fixed on a monthly basis, consistent with Commission Order No. 24,682 in the Unitil Energy Systems Docket DE 06-123".

Unitil Energy Systems, Inc.

Time Differentiated Default Service Charge
Effective August 1, 2024 through January 31, 2025

	For August 1, 2024 through November 30, 2024			For December 1, 2024 through January 31, 2025		
	Summer Volumetric Rates (1) Jun 1 - Nov 30	Ratios to Current Rate	Ratios Applied to August 1, 2024 Rates	Winter Volumetric Rates (1) Dec 1 - May 31	Ratios to Current Rate	Ratios Applied to August 1, 2024 Rates
Schedule TOU-D and Schedule TOU-EV-D						
6/1/20 and 12/1/20 DS Chg with annual RPS	*$ 0.07011*	*8/1/24 DS Chg*	*$ 0.10506*	*$ 0.09291*	*8/1/24 DS Chg*	*$ 0.10506*
Default Service Charge:						
Off Peak kWH	$ 0.05885	0.84	$ 0.08819	$ 0.05833	0.63	$ 0.06596
Mid Peak kWh	$ 0.07266	1.04	$ 0.10888	$ 0.05943	0.64	$ 0.06720
On Peak kWh	$ 0.26801	3.82	$ 0.40161	$ 0.07151	0.77	$ 0.08086
Schedule TOU-EV-G2						
6/1/20 and 12/1/20 DS Chg with annual RPS	*$ 0.05897*	*8/1/24 DS Chg*	*$ 0.10027*	*$ 0.08678*	*8/1/24 DS Chg*	*$ 0.10027*
Default Service Charge:						
Off Peak kWH	$ 0.04919	0.83	$ 0.08364	$ 0.05390	0.62	$ 0.06228
Mid Peak kWh	$ 0.06216	1.05	$ 0.10569	$ 0.05620	0.65	$ 0.06494
On Peak kWh	$ 0.25774	4.37	$ 0.43825	$ 0.06809	0.78	$ 0.07867

Off Peak kWH (M-F 8 pm - 6 am, all day weekends and weekday holidays)
Mid Peak kWh (M-F 6 am -3 pm excluding weekday holidays)
On Peak kWh (M-F 3 pm - 8 pm excluding weekday holidays)

Comparison of Rates and Ratios from Exh. 24 Revised Attachment A
to August 1, 2024 through January 31, 2025 Rates and Ratios

	Summer Volumetric Rates Exh.24 Revised Attachment A	Ratio to Mid-Peak	**August 1, 2024 to November 30, 2024** Volumetric Rates	Ratio to Mid-Peak	Winter Volumetric Rates Exh.24 Revised Attachment A	Ratio to Mid-Peak	**December 1, 2024 to January 31, 2025** Volumetric Rates	Ratio to Mid-Peak
Schedule TOU-D and Schedule TOU-EV-D Off Peak kWH	$ 0.05885	81.0%	$ 0.08819	81.0%	$ 0.05833	98.1%	$ 0.06596	98.1%
Mid Peak kWh	$ 0.07266	100.0%	$ 0.10888	100.0%	$ 0.05943	100.0%	$ 0.06720	100.0%
On Peak kWh	$ 0.26801	368.9%	$ 0.40161	368.9%	$ 0.07151	120.3%	$ 0.08086	120.3%
Schedule TOU-EV-G2 Off Peak kWH	$ 0.04919	79.1%	$ 0.08364	79.1%	$ 0.05390	95.9%	$ 0.06228	95.9%
Mid Peak kWh	$ 0.06216	100.0%	$ 0.10569	100.0%	$ 0.05620	100.0%	$ 0.06494	100.0%
On Peak kWh	$ 0.25774	414.6%	$ 0.43825	414.6%	$ 0.06809	121.2%	$ 0.07867	121.2%

(1) Time Of Use Rates - See DE 20-170 Exhibit 24 Revised, Attachment A Illustrative Rates

REDACTED

Unitil Energy Systems, Inc.
Typical Bill Impacts by Rate Component

Residential Rate D 650 kWh Bill

Rate Components	6/1/2024 Current Rate	8/1/2024 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Bill Component	% Difference to Total Bill
Customer Charge	$16.22	$16.22	$0.00	$16.22	$16.22	$0.00	0.0%	0.0%
	$/kWh	$/kWh						
Distribution Charge	$0.04612	$0.04612	$0.00000	$29.98	$29.98	$0.00	0.0%	0.0%
External Delivery Charge	$0.04486	$0.04486	$0.00000	$29.16	$29.16	$0.00	0.0%	0.0%
Stranded Cost Charge	($0.00010)	($0.00010)	$0.00000	($0.07)	($0.07)	$0.00	0.0%	0.0%
Storm Recovery Adj.	$0.00114	$0.00114	$0.00000	$0.74	$0.74	$0.00	0.0%	0.0%
System Benefits Charge	$0.00727	$0.00727	$0.00000	$4.73	$4.73	$0.00	0.0%	0.0%
Revenue Decoupling Adj.	$0.00186	$0.00186	$0.00000	$1.21	$1.21	$0.00	0.0%	0.0%
Default Service Charge	$0.10718	$0.10506	($0.00212)	$69.67	$68.29	($1.38)	(2.0%)	(0.9%)
Total kWh Charges	$0.20833	$0.20621	($0.00212)					
Total Bill				$151.63	$150.26	($1.38)	(0.9%)	(0.9%)

Regular General G2 Demand, 11 kW, 2,800 kWh Typical Bill

Rate Components	6/1/2024 Current Rate	8/1/2024 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Bill Component	% Difference to Total Bill
Customer Charge	$29.19	$29.19	$0.00	$29.19	$29.19	$0.00	0.0%	0.0%
	All kW	All kW						
Distribution Charge	$12.13	$12.13	$0.00	$133.43	$133.43	$0.00	0.0%	0.0%
Stranded Cost Charge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	0.0%	0.0%
Total kW Charges	$12.13	$12.13	$0.00	$133.43	$133.43	$0.00	0.0%	0.0%
	$/kWh	$/kWh						
Distribution Charge	$0.00000	$0.00000	$0.00000	$0.00	$0.00	$0.00	0.0%	0.0%
External Delivery Charge	$0.04486	$0.04486	$0.00000	$125.61	$125.61	$0.00	0.0%	0.0%
Stranded Cost Charge	($0.00010)	($0.00010)	$0.00000	($0.28)	($0.28)	$0.00	0.0%	0.0%
Storm Recovery Adj.	$0.00114	$0.00114	$0.00000	$3.19	$3.19	$0.00	0.0%	0.0%
System Benefits Charge	$0.00727	$0.00727	$0.00000	$20.36	$20.36	$0.00	0.0%	0.0%
Revenue Decoupling Adj.	($0.00002)	($0.00002)	$0.00000	($0.06)	($0.06)	$0.00	0.0%	0.0%
Default Service Charge	$0.10038	$0.10027	($0.00011)	$281.06	$280.76	($0.31)	(0.1%)	(0.1%)
Total kWh Charges	$0.15353	$0.15342	($0.00011)	$429.88	$429.58	($0.31)	(0.1%)	(0.1%)
Total Bill				$592.50	$592.20	($0.31)	(0.1%)	(0.1%)

Unitil Energy Systems, Inc.
Typical Bill Impacts by Rate Component

Regular General G2 Quick Recovery Water Heating and Space Heating 1,660 kWh Typical Bill

Rate Components	6/1/2024 Current Rate	8/1/2024 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Bill Component	% Difference to Total Bill
Customer Charge	$9.73	$9.73	$0.00	$9.73	$9.73	$0.00	0.0%	0.0%
	$/kWh	**$/kWh**						
Distribution Charge	$0.03669	$0.03669	$0.00000	$60.91	$60.91	$0.00	0.0%	0.0%
External Delivery Charge	$0.04486	$0.04486	$0.00000	$74.47	$74.47	$0.00	0.0%	0.0%
Stranded Cost Charge	($0.00010)	($0.00010)	$0.00000	($0.17)	($0.17)	$0.00	0.0%	0.0%
Storm Recovery Adj.	$0.00114	$0.00114	$0.00000	$1.89	$1.89	$0.00	0.0%	0.0%
System Benefits Charge	$0.00727	$0.00727	$0.00000	$12.07	$12.07	$0.00	0.0%	0.0%
Revenue Decoupling Adj.	($0.00002)	($0.00002)	$0.00000	($0.03)	($0.03)	$0.00	0.0%	0.0%
Default Service Charge	$0.10038	$0.10027	($0.00011)	$166.63	$166.45	($0.18)	(0.1%)	(0.1%)
Total kWh Charges	$0.19022	$0.19011	($0.00011)	$315.77	$315.58	($0.18)	(0.1%)	(0.1%)
Total Bill				$325.50	$325.31	($0.18)	(0.1%)	(0.1%)

Regular General G2 kWh Meter 115 kWh Typical Bill

Rate Components	6/1/2024 Current Rate	8/1/2024 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Bill Component	% Difference to Total Bill
Customer Charge	$18.38	$18.38	$0.00	$18.38	$18.38	$0.00	0.0%	0.0%
	$/kWh	**$/kWh**						
Distribution Charge	$0.03270	$0.03270	$0.00000	$3.76	$3.76	$0.00	0.0%	0.0%
External Delivery Charge	$0.04486	$0.04486	$0.00000	$5.16	$5.16	$0.00	0.0%	0.0%
Stranded Cost Charge	($0.00010)	($0.00010)	$0.00000	($0.01)	($0.01)	$0.00	0.0%	0.0%
Storm Recovery Adj.	$0.00114	$0.00114	$0.00000	$0.13	$0.13	$0.00	0.0%	0.0%
System Benefits Charge	$0.00727	$0.00727	$0.00000	$0.84	$0.84	$0.00	0.0%	0.0%
Revenue Decoupling Adj.	($0.00002)	($0.00002)	$0.00000	($0.00)	($0.00)	$0.00	0.0%	0.0%
Default Service Charge	$0.10038	$0.10027	($0.00011)	$11.54	$11.53	($0.01)	(0.1%)	(0.0%)
Total kWh Charges	$0.18623	$0.18612	($0.00011)	$21.42	$21.40	($0.01)	(0.1%)	(0.0%)
Total Bill				$39.80	$39.78	($0.01)	(0.0%)	(0.0%)

Unitil Energy Systems, Inc.
Typical Bill Impacts for Residential Rate Class based on Mean and Median Usage

Residential Rate D 617 kWh Bill - Mean Use*

	6/1/2024	8/1/2024					%	%
Rate Components	Current Rate	As Revised	Difference	Current Bill	As Revised Bill	Difference	Difference to Bill Component	Difference to Total Bill
Customer Charge	$16.22	$16.22	$0.00	$16.22	$16.22	$0.00	0.0%	0.0%
	$/kWh	**$/kWh**						
Distribution Charge	$0.04612	$0.04612	$0.00000	$28.46	$28.46	$0.00	0.0%	0.0%
External Delivery Charge	$0.04486	$0.04486	$0.00000	$27.68	$27.68	$0.00	0.0%	0.0%
Stranded Cost Charge	($0.00010)	($0.00010)	$0.00000	($0.06)	($0.06)	$0.00	0.0%	0.0%
Storm Recovery Adj.	$0.00114	$0.00114	$0.00000	$0.70	$0.70	$0.00	0.0%	0.0%
System Benefits Charge	$0.00727	$0.00727	$0.00000	$4.49	$4.49	$0.00	0.0%	0.0%
Revenue Decoupling Adj.	$0.00186	$0.00186	$0.00000	$1.15	$1.15	$0.00	0.0%	0.0%
Default Service Charge	$0.10718	$0.10506	($0.00212)	$66.13	$64.82	($1.31)	(2.0%)	(0.9%)
Total kWh Charges	$0.20833	$0.20621	($0.00212)					
Total Bill				$144.76	$143.45	($1.31)	(0.9%)	(0.9%)

Residential Rate D 490 kWh Bill - Median Use*

	6/1/2024	8/1/2024					%	%
Rate Components	Current Rate	As Revised	Difference	Current Bill	As Revised Bill	Difference	Difference to Bill Component	Difference to Total Bill
Customer Charge	$16.22	$16.22	$0.00	$16.22	$16.22	$0.00	0.0%	0.0%
	$/kWh	**$/kWh**						
Distribution Charge	$0.04612	$0.04612	$0.00000	$22.60	$22.60	$0.00	0.0%	0.0%
External Delivery Charge	$0.04486	$0.04486	$0.00000	$21.98	$21.98	$0.00	0.0%	0.0%
Stranded Cost Charge	($0.00010)	($0.00010)	$0.00000	($0.05)	($0.05)	$0.00	0.0%	0.0%
Storm Recovery Adj.	$0.00114	$0.00114	$0.00000	$0.56	$0.56	$0.00	0.0%	0.0%
System Benefits Charge	$0.00727	$0.00727	$0.00000	$3.56	$3.56	$0.00	0.0%	0.0%
Revenue Decoupling Adj.	$0.00186	$0.00186						
Default Service Charge	$0.10718	$0.10506	($0.00212)	$52.52	$51.48	($1.04)	(2.0%)	(0.9%)
Total kWh Charges	$0.20833	$0.20621	($0.00212)					
Total Bill				$117.39	$116.35	($1.04)	(0.9%)	(0.9%)

* Based on billing period January through December 2023.

Unitil Energy Systems, Inc.
Average Class Impacts
Due to Proposed Default Service Rate Changes Effective August 1, 2024

(A) Class of Service	(B) Annual Number of Customers (luminaires for Outdoor Lighting)	(C) Annual kWh Sales	(D) Annual kW / kVA Sales	(E) Proposed DSC Change $	(F) Estimated Annual Revenue $ Under Present Rates	(G) Estimated Annual Revenue $ Under Proposed Rates	(H) Proposed Net Change Revenue $	(I) % Change DSC Revenue
Residential	815,280	515,968,592	n/a	($1,093,853)	$120,715,570	$119,621,717	($1,093,853)	(0.9%)
General Service	134,344	317,056,821	1,234,532	($34,876)	$67,625,318	$67,590,441	($34,876)	(0.1%)
Outdoor Lighting	108,601	7,625,729	n/a	($839)	$3,028,645	$3,027,806	($839)	(0.0%)
Total	1,058,224	840,651,142		($1,129,568)	$191,369,533	$190,239,964	($1,129,568)	(0.6%)

(B), (C), (D) Test year billing determinants in DE 21-030.
(E) Difference in proposed rate and current rate, times the billing determinants shown in Column (C).
(F) Based on current rates times billing determinants shown in Columns (B), (C) and (D).
(G) Sum of Columns (E) and (F)
(H) Column (G) minus Column (F)
(I) Column (H) divided by Column (F)

Unitil Energy Systems, Inc.
Typical Bill Impacts - June 1, 2024 vs. August 1, 2024
Due to Changes in the Default Service Charage
Impact on D Rate Customers

Average kWh	Total Bill Using Rates 6/1/2024	Total Bill Using Rates 8/1/2024	Total Difference	% Total Difference
125	$42.26	$42.00	($0.26)	(0.63%)
150	$47.47	$47.15	($0.32)	(0.67%)
200	$57.89	$57.46	($0.42)	(0.73%)
250	$68.30	$67.77	($0.53)	(0.78%)
300	$78.72	$78.08	($0.64)	(0.81%)
350	$89.14	$88.39	($0.74)	(0.83%)
400	$99.55	$98.70	($0.85)	(0.85%)
450	$109.97	$109.01	($0.95)	(0.87%)
500	$120.39	$119.33	($1.06)	(0.88%)
525	$125.59	$124.48	($1.11)	(0.89%)
550	$130.80	$129.64	($1.17)	(0.89%)
575	$136.01	$134.79	($1.22)	(0.90%)
600	$141.22	$139.95	($1.27)	(0.90%)
625	$146.43	$145.10	($1.32)	(0.90%)
650	$151.63	$150.26	($1.38)	(0.91%)
675	$156.84	$155.41	($1.43)	(0.91%)
700	$162.05	$160.57	($1.48)	(0.92%)
725	$167.26	$165.72	($1.54)	(0.92%)
750	$172.47	$170.88	($1.59)	(0.92%)
775	$177.68	$176.03	($1.64)	(0.92%)
825	$188.09	$186.34	($1.75)	(0.93%)
925	$208.93	$206.96	($1.96)	(0.94%)
1,000	$224.55	$222.43	($2.12)	(0.94%)
1,250	$276.63	$273.98	($2.65)	(0.96%)
1,500	$328.72	$325.54	($3.18)	(0.97%)
2,000	$432.88	$428.64	($4.24)	(0.98%)
3,500	$745.38	$737.96	($7.42)	(1.00%)
5,000	$1,057.87	$1,047.27	($10.60)	(1.00%)

	Rates - Effective June 1, 2024	Rates - Proposed August 1, 2024	Difference
Customer Charge	**$16.22**	**$16.22**	**$0.00**
	kWh	kWh	kWh
Distribution Charge:	$0.04612	$0.04612	$0.00000
External Delivery Charge	$0.04486	$0.04486	$0.00000
Stranded Cost Charge	($0.00010)	($0.00010)	$0.00000
Storm Recovery Adjustment Factor	$0.00114	$0.00114	$0.00000
System Benefits Charge	$0.00727	$0.00727	$0.00000
Revenue Decoupling Adjustment Factor	$0.00186	$0.00186	$0.00000
Default Service Charge	$0.10718	$0.10506	($0.00212)
TOTAL	**$0.20833**	**$0.20621**	**($0.00212)**

Unitil Energy Systems, Inc.
Typical Bill Impacts - June 1, 2024 vs. August 1, 2024
Due to Changes in the Default Service Charage
Impact on G2 Rate Customers

Load Factor	Average Monthly kW	Average Monthly kWh	Total Bill Using Rates 6/1/2024	Total Bill Using Rates 8/1/2024	Total Difference	% Total Difference
20%	5	730	$201.92	$201.84	($0.08)	(0.04%)
20%	10	1,460	$374.64	$374.48	($0.16)	(0.04%)
20%	15	2,190	$547.37	$547.13	($0.24)	(0.04%)
20%	25	3,650	$892.82	$892.42	($0.40)	(0.04%)
20%	50	7,300	$1,756.46	$1,755.66	($0.80)	(0.05%)
20%	75	10,950	$2,620.09	$2,618.89	($1.20)	(0.05%)
20%	100	14,600	$3,483.73	$3,482.12	($1.61)	(0.05%)
20%	150	21,900	$5,211.00	$5,208.59	($2.41)	(0.05%)
36%	5	1,314	$291.58	$291.43	($0.14)	(0.05%)
36%	10	2,628	$553.97	$553.68	($0.29)	(0.05%)
36%	15	3,942	$816.36	$815.92	($0.43)	(0.05%)
36%	25	6,570	$1,341.13	$1,340.41	($0.72)	(0.05%)
36%	50	13,140	$2,653.07	$2,651.63	($1.45)	(0.05%)
36%	75	19,710	$3,965.02	$3,962.85	($2.17)	(0.05%)
36%	100	26,280	$5,276.96	$5,274.07	($2.89)	(0.05%)
36%	150	39,420	$7,900.84	$7,896.51	($4.34)	(0.05%)
50%	5	1,825	$370.03	$369.83	($0.20)	(0.05%)
50%	10	3,650	$710.87	$710.47	($0.40)	(0.06%)
50%	15	5,475	$1,051.72	$1,051.11	($0.60)	(0.06%)
50%	25	9,125	$1,733.40	$1,732.40	($1.00)	(0.06%)
50%	50	18,250	$3,437.61	$3,435.61	($2.01)	(0.06%)
50%	75	27,375	$5,141.82	$5,138.81	($3.01)	(0.06%)
50%	100	36,500	$6,846.04	$6,842.02	($4.01)	(0.06%)
50%	150	54,750	$10,254.46	$10,248.44	($6.02)	(0.06%)

	Rates - Effective June 1, 2024	Rates - Proposed August 1, 2024	Difference
Customer Charge	**$29.19**	**$29.19**	**$0.00**
	All kW	**All kW**	**All kW**
Distribution Charge	$12.13	$12.13	$0.00
Stranded Cost Charge	$0.00	$0.00	$0.00
TOTAL	**$12.13**	**$12.13**	**$0.00**
	kWh	**kWh**	**kWh**
Distribution Charge	$0.00000	$0.00000	$0.00000
External Delivery Charge	$0.04486	$0.04486	$0.00000
Stranded Cost Charge	($0.00010)	($0.00010)	$0.00000
Storm Recovery Adj. Factor	$0.00114	$0.00114	$0.00000
System Benefits Charge	$0.00727	$0.00727	$0.00000
Revenue Decoupling Adjustment Factor	($0.00002)	($0.00002)	$0.00000
Default Service Charge	$0.10038	$0.10027	($0.00011)
TOTAL	**$0.15353**	**$0.15342**	**($0.00011)**

REDACTED

Unitil Energy Systems, Inc.
Typical Bill Impacts - June 1, 2024 vs. August 1, 2024
Due to Changes in the Default Service Charage
Impact on G2 kWh Meter Rate Customers

Average Monthly kWh	Total Bill Using Rates 6/1/2024	Total Bill Using Rates 8/1/2024	Total Difference	% Total Difference
15	$21.17	$21.17	($0.00)	(0.01%)
75	$32.35	$32.34	($0.01)	(0.03%)
150	$46.31	$46.30	($0.02)	(0.04%)
250	$64.94	$64.91	($0.03)	(0.04%)
350	$83.56	$83.52	($0.04)	(0.05%)
450	$102.18	$102.13	($0.05)	(0.05%)
550	$120.81	$120.75	($0.06)	(0.05%)
650	$139.43	$139.36	($0.07)	(0.05%)
750	$158.05	$157.97	($0.08)	(0.05%)
900	$185.99	$185.89	($0.10)	(0.05%)

	Rates - Effective June 1, 2024	Rates - Proposed August 1, 2024	Difference
Customer Charge	**$18.38**	**$18.38**	**$0.00**
	All kWh	**All kWh**	**All kWh**
Distribution Charge	$0.03270	$0.03270	$0.00000
External Delivery Charge	$0.04486	$0.04486	$0.00000
Stranded Cost Charge	($0.00010)	($0.00010)	$0.00000
Storm Recovery Adjustment Factor	$0.00114	$0.00114	$0.00000
System Benefits Charge	$0.00727	$0.00727	$0.00000
Revenue Decoupling Adjustment Factor	($0.00002)	($0.00002)	$0.00000
Default Service Charge	$0.10038	$0.10027	($0.00011)
TOTAL	**$0.18623**	**$0.18612**	**($0.00011)**

REDACTED

Unitil Energy Systems, Inc.
Typical Bill Impacts - June 1, 2024 vs. August 1, 2024
Due to Changes in the Default Service Charage
Impact on G2 QRWH and SH Rate Customers

Average kWh	Total Bill Using Rates 6/1/2024	Total Bill Using Rates 8/1/2024	Total Difference	% Total Difference
100	$28.75	$28.74	($0.01)	(0.04%)
200	$47.77	$47.75	($0.02)	(0.05%)
300	$66.80	$66.76	($0.03)	(0.05%)
400	$85.82	$85.77	($0.04)	(0.05%)
500	$104.84	$104.79	($0.05)	(0.05%)
750	$152.40	$152.31	($0.08)	(0.05%)
1,000	$199.95	$199.84	($0.11)	(0.06%)
1,500	$295.06	$294.90	($0.16)	(0.06%)
2,000	$390.17	$389.95	($0.22)	(0.06%)
2,500	$485.28	$485.01	($0.28)	(0.06%)

	Rates - Effective June 1, 2024	Rates - Proposed August 1, 2024	Difference
Customer Charge	**$9.73**	**$9.73**	**$0.00**
	All kWh	**All kWh**	**All kWh**
Distribution Charge	$0.03669	$0.03669	$0.00000
External Delivery Charge	$0.04486	$0.04486	$0.00000
Stranded Cost Charge	($0.00010)	($0.00010)	$0.00000
Storm Recovery Adjustment Factor	$0.00114	$0.00114	$0.00000
System Benefits Charge	$0.00727	$0.00727	$0.00000
Revenue Decoupling Adjustment Factor	($0.00002)	($0.00002)	$0.00000
Default Service Charge	$0.10038	$0.10027	($0.00011)
TOTAL	**$0.19022**	**$0.19011**	**($0.00011)**

Unitil Energy Systems, Inc.
Typical Bill Impacts - June 1, 2024 vs. August 1, 2024
Due to Changes in the Default Service Charage
Impact on OL Rate Customers *

	Nominal Watts	Lumens	Type	Average Monthly kWh	Total Bill Using Rates 6/1/2024	Total Bill Using Rates 8/1/2024	Total Difference	% Total Difference
	Mercury Vapor:							
1	100	3,500	ST	43	$20.33	$20.33	($0.00)	(0.02%)
2	175	7,000	ST	71	$26.63	$26.62	($0.01)	(0.03%)
3	250	11,000	ST	100	$32.61	$32.59	($0.01)	(0.03%)
4	400	20,000	ST	157	$41.36	$41.34	($0.02)	(0.04%)
5	1,000	60,000	ST	372	$81.90	$81.86	($0.04)	(0.05%)
6	250	11,000	FL	100	$33.61	$33.59	($0.01)	(0.03%)
7	400	20,000	FL	157	$45.68	$45.66	($0.02)	(0.04%)
8	1,000	60,000	FL	380	$83.64	$83.60	($0.04)	(0.05%)
9	100	3,500	PB	48	$20.81	$20.81	($0.01)	(0.03%)
10	175	7,000	PB	71	$25.55	$25.54	($0.01)	(0.03%)
	High Pressure Sodium:							
11	50	4,000	ST	23	$17.26	$17.26	($0.00)	(0.01%)
12	100	9,500	ST	48	$23.10	$23.10	($0.01)	(0.02%)
13	150	16,000	ST	65	$27.23	$27.22	($0.01)	(0.03%)
14	250	30,000	ST	102	$35.19	$35.18	($0.01)	(0.03%)
15	400	50,000	ST	161	$49.50	$49.48	($0.02)	(0.04%)
16	1,000	140,000	ST	380	$100.86	$100.82	($0.04)	(0.04%)
17	150	16,000	FL	65	$28.23	$28.22	($0.01)	(0.03%)
18	250	30,000	FL	102	$37.23	$37.22	($0.01)	(0.03%)
19	400	50,000	FL	161	$50.01	$49.99	($0.02)	(0.04%)
20	1,000	140,000	FL	380	$101.24	$101.20	($0.04)	(0.04%)
21	50	4,000	PB	23	$16.97	$16.97	($0.00)	(0.01%)
22	100	95,000	PB	48	$22.02	$22.02	($0.01)	(0.02%)
	Metal Halide:							
23	175	8,800	ST	74	$28.61	$28.60	($0.01)	(0.03%)
24	1,000	86,000	FL	374	$82.72	$82.68	($0.04)	(0.05%)
	LED							
25	35	3,000	AL	12	$15.28	$15.28	($0.00)	(0.01%)
26	47	4,000	AL	16	$17.11	$17.11	($0.00)	(0.01%)
27	30	3,300	ST	10	$15.27	$15.26	($0.00)	(0.01%)
28	50	5,000	ST	17	$18.34	$18.34	($0.00)	(0.01%)
29	100	11,000	ST	35	$22.62	$22.62	($0.00)	(0.02%)
30	120	18,000	ST	42	$25.98	$25.97	($0.00)	(0.02%)
31	140	18,000	ST	48	$32.15	$32.15	($0.01)	(0.02%)
32	260	31,000	ST	90	$56.33	$56.32	($0.01)	(0.02%)
33	70	10,000	FL	24	$21.94	$21.93	($0.00)	(0.01%)
34	90	10,000	FL	31	$26.33	$26.33	($0.00)	(0.01%)
35	110	15,000	FL	38	$31.12	$31.12	($0.00)	(0.01%)
36	370	46,000	FL	128	$62.54	$62.53	($0.01)	(0.02%)

Luminaire Charges For Year Round Service:

Rates - Effective June 1, 2024		Mercury Vapor Rate/Mo.		Sodium Vapor Rate/Mo.		Metal Halide Rate/Mo.		LED Rate/Mo.	
Customer Charge	**$0.00**	1	$13.73	11	$13.73	23	$17.25	25	$13.44
		2	$15.73	12	$15.73	24	$25.29	26	$14.65
	All kWh	3	$17.25	13	$17.25			27	$13.73
Distribution Charge	$0.00000	4	$17.25	14	$19.53			28	$15.73
External Delivery Charge	$0.04486	5	$24.78	15	$24.78			29	$17.25
Stranded Cost Charge	($0.00010)	6	$18.25	16	$42.51			30	$19.53
Storm Recovery Adj. Factor	$0.00114	7	$21.57	17	$18.25			31	$24.78
System Benefits Charge	$0.00727	8	$25.29	18	$21.57			32	$42.51
Default Service Charge	$0.10038	9	$13.44	19	$25.29			33	$18.25
		10	$14.65	20	$42.89			34	$21.57
TOTAL	**$0.15355**			21	$13.44			35	$25.29
				22	$14.65			36	$42.89

Rates - Proposed August 1, 2024		Mercury Vapor Rate/Mo.		Sodium Vapor Rate/Mo.		Metal Halide Rate/Mo.		LED Rate/Mo.	
Customer Charge	**$0.00**	1	$13.73	11	$13.73	23	$17.25	25	$13.44
		2	$15.73	12	$15.73	24	$25.29	26	$14.65
	All kWh	3	$17.25	13	$17.25			27	$13.73
Distribution Charge	$0.00000	4	$17.25	14	$19.53			28	$15.73
External Delivery Charge	$0.04486	5	$24.78	15	$24.78			29	$17.25
Stranded Cost Charge	($0.00010)	6	$18.25	16	$42.51			30	$19.53
Storm Recovery Adj. Factor	$0.00114	7	$21.57	17	$18.25			31	$24.78
System Benefits Charge	$0.00727	8	$25.29	18	$21.57			32	$42.51
Default Service Charge	$0.10027	9	$13.44	19	$25.29			33	$18.25
		10	$14.65	20	$42.89			34	$21.57
TOTAL	**$0.15344**			21	$13.44			35	$25.29
				22	$14.65			36	$42.89

Difference		Mercury Vapor Rate/Mo.		Sodium Vapor Rate/Mo.		Metal Halide Rate/Mo.		LED Rate/Mo.	
Customer Charge	**$0.00**	1	$0.00	11	$0.00	23	$0.00	25	$0.00
		2	$0.00	12	$0.00	24	$0.00	26	$0.00
	All kWh	3	$0.00	13	$0.00			27	$0.00
Distribution Charge	$0.00000	4	$0.00	14	$0.00			28	$0.00
External Delivery Charge	$0.00000	5	$0.00	15	$0.00			29	$0.00
Stranded Cost Charge	$0.00000	6	$0.00	16	$0.00			30	$0.00
Storm Recovery Adj. Factor	$0.00000	7	$0.00	17	$0.00			31	$0.00
System Benefits Charge	$0.00000	8	$0.00	18	$0.00			32	$0.00
Default Service Charge	($0.00011)	9	$0.00	19	$0.00			33	$0.00
		10	$0.00	20	$0.00			34	$0.00
TOTAL	**($0.00011)**			21	$0.00			35	$0.00
				22	$0.00			36	$0.00

* Luminaire charges based on All-Night Service option.

REDACTED

Unitil Energy Systems, Inc.
Typical Bill Impacts - June 1, 2024 vs. August 1, 2024
Due to Changes in the Default Service Charage
Impact on Tariffed Customer Supplied LED Rate Customers

	Nominal Watts	Lumens	Type	Current Average Monthly kWh	Percentage of Lights	Total Bill Using Rates 6/1/2024	Total Bill Using Rates 8/1/2024	Total Difference	% Total Difference
	CS LED								
1	35	3,000	AL	12	0.0%	$8.84	$8.84	($0.00)	(0.01%)
2	47	4,000	AL	16	0.0%	$10.67	$10.67	($0.00)	(0.02%)
3	30	3,300	ST	10	0.0%	$11.25	$11.24	($0.00)	(0.01%)
4	50	5,000	ST	17	0.0%	$14.53	$14.53	($0.00)	(0.01%)
5	100	11,000	ST	35	0.0%	$17.85	$17.85	($0.00)	(0.02%)
6	120	18,000	ST	42	0.0%	$21.21	$21.20	($0.00)	(0.02%)
7	140	18,000	ST	48	0.0%	$25.20	$25.20	($0.01)	(0.02%)
8	260	31,000	ST	90	0.0%	$47.38	$47.37	($0.01)	(0.02%)
9	70	10,000	FL	24	0.0%	$14.93	$14.92	($0.00)	(0.02%)
10	90	10,000	FL	31	0.0%	$19.32	$19.32	($0.00)	(0.02%)
11	110	15,000	FL	38	0.0%	$23.19	$23.19	($0.00)	(0.02%)
12	370	46,000	FL	128	0.0%	$46.65	$46.64	($0.01)	(0.03%)

Rates - Effective June 1, 2024		**Rates - Proposed August 1, 2024**		**Difference**	
Customer Charge	**$0.00**	Customer Charge	**$0.00**	Customer Charge	**$0.00**
	All kWh		**All kWh**		
Distribution Charge	$0.00000	Distribution Charge	$0.00000	Distribution Charge	$0.00000
External Delivery Charge	$0.04486	External Delivery Charge	$0.04486	External Delivery Charge	$0.00000
Stranded Cost Charge	($0.00010)	Stranded Cost Charge	($0.00010)	Stranded Cost Charge	$0.00000
Storm Recovery Adj. Factor	$0.00114	Storm Recovery Adj. Factor	$0.00114	Storm Recovery Adj. Factor	$0.00000
System Benefits Charge	$0.00727	System Benefits Charge	$0.00727	System Benefits Charge	$0.00000
Fixed Default Service Charge	$0.10038	Fixed Default Service Charge	$0.10027	Fixed Default Service Charge	($0.00011)
TOTAL	**$0.15355**	**TOTAL**	**$0.15344**	**TOTAL**	**($0.00011)**

Luminaire Charges:		**Luminaire Charges:**		**Luminaire Charges:**	
	CS LED Rate/Mo.		CS LED Rate/Mo.		
1	$7.00	1	$7.00	1	**$0.00**
2	$8.21	2	$8.21	2	**$0.00**
3	$9.71	3	$9.71	3	**$0.00**
4	$11.92	4	$11.92	4	**$0.00**
5	$12.48	5	$12.48	5	**$0.00**
6	$14.76	6	$14.76	6	**$0.00**
7	$17.83	7	$17.83	7	**$0.00**
8	$33.56	8	$33.56	8	**$0.00**
9	$11.24	9	$11.24	9	**$0.00**
10	$14.56	10	$14.56	10	**$0.00**
11	$17.36	11	$17.36	11	**$0.00**
12	$27.00	12	$27.00	12	**$0.00**

Unitil Energy Systems, Inc.
Typical Bill Impacts by Rate Component

Residential Rate D 650 kWh Bill

Rate Components	8/1/2023 Current Rate	8/1/2024 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Bill Component	% Difference to Total Bill
Customer Charge	$16.22	$16.22	$0.00	$16.22	$16.22	$0.00	0.0%	0.0%
	$/kWh	**$/kWh**						
Distribution Charge	$0.04612	$0.04612	$0.00000	$29.98	$29.98	$0.00	0.0%	0.0%
External Delivery Charge	$0.04486	$0.04486	$0.00000	$29.16	$29.16	$0.00	0.0%	0.0%
Stranded Cost Charge	($0.00010)	($0.00010)	$0.00000	($0.07)	($0.07)	$0.00	0.0%	0.0%
Storm Recovery Adj.	$0.00000	$0.00114	$0.00114	$0.00	$0.74	$0.74	n/a	0.4%
System Benefits Charge	$0.00700	$0.00727	$0.00027	$4.55	$4.73	$0.18	3.9%	0.1%
Revenue Decoupling Adj.	$0.00186	$0.00186	$0.00000	$1.21	$1.21	$0.00	0.0%	0.0%
Default Service Charge	$0.13257	$0.10506	($0.02751)	$86.17	$68.29	($17.88)	(20.8%)	(10.7%)
Total kWh Charges	$0.23231	$0.20621	($0.02610)					
Total Bill				$167.22	$150.26	($16.97)	(10.1%)	(10.1%)

Regular General G2 Demand, 11 kW, 2,800 kWh Typical Bill

Rate Components	8/1/2023 Current Rate	8/1/2024 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Bill Component	% Difference to Total Bill
Customer Charge	$29.19	$29.19	$0.00	$29.19	$29.19	$0.00	0.0%	0.0%
	All kW	**All kW**						
Distribution Charge	$12.13	$12.13	$0.00	$133.43	$133.43	$0.00	0.0%	0.0%
Stranded Cost Charge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	0.0%	0.0%
Total kW Charges	$12.13	$12.13	$0.00	$133.43	$133.43	$0.00	0.0%	0.0%
	$/kWh	**$/kWh**						
Distribution Charge	$0.00000	$0.00000	$0.00000	$0.00	$0.00	$0.00	0.0%	0.0%
External Delivery Charge	$0.04486	$0.04486	$0.00000	$125.61	$125.61	$0.00	0.0%	0.0%
Stranded Cost Charge	($0.00010)	($0.00010)	$0.00000	($0.28)	($0.28)	$0.00	0.0%	0.0%
Storm Recovery Adj.	$0.00000	$0.00114	$0.00114	$0.00	$3.19	$3.19	n/a	0.5%
System Benefits Charge	$0.00700	$0.00727	$0.00027	$19.60	$20.36	$0.76	3.9%	0.1%
Revenue Decoupling Adj.	($0.00002)	($0.00002)	$0.00000	($0.06)	($0.06)	$0.00	0.0%	0.0%
Default Service Charge	$0.12794	$0.10027	($0.02767)	$358.23	$280.76	($77.48)	(21.6%)	(11.6%)
Total kWh Charges	$0.17968	$0.15342	($0.02626)	$503.10	$429.58	($73.53)	(14.6%)	(11.0%)
Total Bill				$665.72	$592.20	($73.53)	(11.0%)	(11.0%)

Unitil Energy Systems, Inc.
Typical Bill Impacts by Rate Component

Regular General G2 Quick Recovery Water Heating and Space Heating 1,660 kWh Typical Bill

Rate Components	8/1/2023 Current Rate	8/1/2024 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Bill Component	% Difference to Total Bill
Customer Charge	$9.73	$9.73	$0.00	$9.73	$9.73	$0.00	0.0%	0.0%
	$/kWh	$/kWh						
Distribution Charge	$0.03669	$0.03669	$0.00000	$60.91	$60.91	$0.00	0.0%	0.0%
External Delivery Charge	$0.04486	$0.04486	$0.00000	$74.47	$74.47	$0.00	0.0%	0.0%
Stranded Cost Charge	($0.00010)	($0.00010)	$0.00000	($0.17)	($0.17)	$0.00	0.0%	0.0%
Storm Recovery Adj.	$0.00000	$0.00114	$0.00114	$0.00	$1.89	$1.89	n/a	0.5%
System Benefits Charge	$0.00700	$0.00727	$0.00027	$11.62	$12.07	$0.45	3.9%	0.1%
Revenue Decoupling Adj.	($0.00002)	($0.00002)	$0.00000	($0.03)	($0.03)	$0.00	0.0%	0.0%
Default Service Charge	$0.12794	$0.10027	($0.02767)	$212.38	$166.45	($45.93)	(21.6%)	(12.5%)
Total kWh Charges	$0.21637	$0.19011	($0.02626)	$359.17	$315.58	($43.59)	(12.1%)	(11.8%)
Total Bill				$368.90	$325.31	($43.59)	(11.8%)	(11.8%)

Regular General G2 kWh Meter 115 kWh Typical Bill

Rate Components	8/1/2023 Current Rate	8/1/2024 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Bill Component	% Difference to Total Bill
Customer Charge	$18.38	$18.38	$0.00	$18.38	$18.38	$0.00	0.0%	0.0%
	$/kWh	$/kWh						
Distribution Charge	$0.03270	$0.03270	$0.00000	$3.76	$3.76	$0.00	0.0%	0.0%
External Delivery Charge	$0.04486	$0.04486	$0.00000	$5.16	$5.16	$0.00	0.0%	0.0%
Stranded Cost Charge	($0.00010)	($0.00010)	$0.00000	($0.01)	($0.01)	$0.00	0.0%	0.0%
Storm Recovery Adj.	$0.00000	$0.00114	$0.00114	$0.00	$0.13	$0.13	n/a	0.3%
System Benefits Charge	$0.00700	$0.00727	$0.00027	$0.81	$0.84	$0.03	3.9%	0.1%
Revenue Decoupling Adj.	($0.00002)	($0.00002)	$0.00000	($0.00)	($0.00)	$0.00	0.0%	0.0%
Default Service Charge	$0.12794	$0.10027	($0.02767)	$14.71	$11.53	($3.18)	(21.6%)	(7.4%)
Total kWh Charges	$0.21238	$0.18612	($0.02626)	$24.42	$21.40	($3.02)	(12.4%)	(7.1%)
Total Bill				$42.80	$39.78	($3.02)	(7.1%)	(7.1%)

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

DANIEL T. NAWAZELSKI

EXHIBIT DTN-1

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Docket No. DE 24-065

Table of Contents

List of Schedules

I. INTRODUCTION

Q. Please state your names and business address.

A. My name is Daniel T. Nawazelski, and my business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. Mr. Nawazelski, what is your position and what are your responsibilities?

A. I am the Manager of Revenue Requirements for Unitil Service Corp. ("Unitil Service") a subsidiary of Unitil Corporation that provides managerial, financial, regulatory and engineering services to Unitil Corporation's utility subsidiaries including Unitil Energy Systems, Inc., ("UES" or the "Company"). In this capacity I am responsible for the preparation and presentation of distribution rate cases and in support of other various regulatory proceedings.

Q. Mr. Nawazelski, please describe your business and educational background.

A. I began working for Unitil Service in June of 2012 as an Associate Financial Analyst and have held various positions with increasing responsibilities leading to my current role of Manager of Revenue Requirements. I earned a Bachelor of Science degree in Business with a concentration in Finance and Operations Management from the University of Massachusetts, Amherst in May of 2012. I am also currently pursuing my Masters in Business Administration at the University of New Hampshire.

Q. Have you previously testified before the Commission or other regulatory agencies?

A. Yes, I testified before this Commission on various financial, ratemaking and utility regulation matters. I have also testified in proceedings before the Maine Public Utilities Commission and the Massachusetts Department of Public Utilities.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I will discuss the development of the 2023 UES Default Service and Renewable Energy Credits Lead Lag Study ("2023 Study"), which is integral to the calculation of cash working capital to be recovered in Default Service rates for G1 and Non-G1 customers.

III. SUMMARY OF TESTIMONY

Q. Please summarize your testimony

A. My testimony presents and supports UES' 2023 Default Service ("DS") and Renewable Energy Credits ("RECs") Lead Lag Study. The 2023 Study, presented in this filing as Schedule DTN-1, is based upon data for the period January 1, 2023 through December 31, 2023 and calculates the net lead period for G1 customers to be 37.59 days and net lag period for Non-G1 customers to be 5.64 days. Finally, as shown in Schedule DTN-3 and described in greater detail below, I have also calculated 48.28 net lag days when the Company is purchasing power directly from the ISO-NE markets ("Self-Supply") consistent with the directives of Order No. 26,973 in Docket No. DE 23-054.

Q. Are the results of the 2023 Study included in the DS rates proposed in this filing?

A. Yes, the 2023 Study results are used to derive supply-related working capital costs included in DS rates beginning August 1, 2024, as described in the testimony of UES witness Linda S. McNamara.

IV. LEAD LAG STUDY METHODLOGY

Q. How was the 2023 Study conducted?

A. The 2023 Study follows similar methodology as in UES' 2022 Default Service and Renewable Energy Credits Lead Lag Study ("2022 Study") that was submitted in Docket No. DE 23-054. The 2023 Study determines the number of days between the time funds are required to pay for DS purchased power and REC purchases (expense lead) and the time that those funds are available from the payment of customer bills (revenue lag). The revenue lag period includes four calculations: "receipt of electric service to meter reading", "meter reading to recording of accounts receivable", "billing to collection", and "collection to receipt of available funds". The expense lead period consists of the lead in payment of DS purchased power costs and REC costs based upon the following calculations: lead period, average days lead, weighted cost, days lead and weighted days lead. Each of these steps is explained in more detail below. UES based its 2023 Study upon data for the twelve months ended December 31, 2023, and calculated net lead lag days separately for the G1 and Non-G1 customer classes.

Q. Does the 2023 Study incorporate the requirements of the Lead Lag Settlement Letter dated July 16, 2009, under docket DE 09-009?

A. Yes, the 2023 Study conforms to the requirements specified in the Settlement Letter under Docket No. DE 09-009. The 2023 Study follows the same methodology as used in the 2009 - 2022 Studies which conform to the requirements of the Settlement.

V. 2023 STUDY RESULTS

Q. Please define the terms "lag days" and "lead days."

A. Lag days are the number of days between delivery of electric service by UES to its customers and the receipt by the Company of available funds from customers' payments (revenue lag). Lead days are the number of days between the mid-point of the energy delivery period to UES and the payment date by UES to DS suppliers or for RECs (expense lead).

Q. How is revenue lag computed?

A. Revenue lag is computed in days, consisting of four time components: (1) days from receipt of electric service to meter reading; (2) days from meter reading to recording of accounts receivable; (3) days from billing to collection; and (4) days from collection to receipt of available funds. The sum of the days associated with these four lag components is the total revenue lag. The calculations are performed separately for G1 and Non-G1 customer classes, as appropriate. Refer to Schedule DTN-1, pages 4 through 19 of 23.

Q. What is the lag period for the component "receipt of electric service to meter reading" in the 2023 Study?

A. The 2023 average lag for "receipt of electric service to meter reading" is 15.21 days. This lag was obtained by dividing the number of days in the test year (365 days) by 24 to determine the average monthly service period. This result is applicable to both the G1 and Non-G1 customer classes. See Schedule DTN-1, page 5 of 23.

Q. What is the lag period for the component "meter reading to recording of accounts receivable?"

A. The 2023 average "meter reading to recording of accounts receivable" lag is 1.04 days, which is applicable to both the G1 and the Non-G1 customer classes. This lag determines the time required to process the meter reading data and record accounts receivable. See Schedule DTN-1, pages 6 through 10 of 23.

Q. What is the lag period for the component "billing to collection?"

A. The 2023 average "billing to collection" lag is 20.51 days for G1 customers and 38.95 days for Non-G1 customers. This component was calculated separately for the G1 and Non-G1 customer groups and is derived by the accounts receivable turnover method. The lag reflects the time delay between the mailing of customer bills and the receipt of the billed revenues from customers. See Schedule DTN-1, pages 11 and 12 of 23 for G1 and Non-G1 results, respectively.

Q. What is the lag period for the component "collection to receipt of available funds?"

A. The 2023 average "collection to receipt of available funds" lag is 1.63 days. This represents the average weighted check-float period, or the lag that takes place during the period from when payment is received from customers to the time such funds are available for use by the Company. This result is applicable to both the G1 and Non-G1 customer classes. See Schedule DTN-1, pages 13 through 19 of 23.

Q. Is the total revenue lag computed from these separate lag calculations?

A. Yes. The total revenue lag of 38.39 days for G1 customers and 56.83 days for Non-G1 customers is computed by adding the number of days associated with each of the four revenue lag components described above. This total number of lag days represents the amount of time between the recorded delivery of service to customers and the receipt of the related revenues from customers. See Schedule DTN-1, page 4, line 6.

Q. Please turn to the lead periods in the 2023 Study. In determining the expense lead period, how is the weighted days lead in payment of DS purchased power costs determined?

A. First, the monthly expense lead for each DS power supply vendor is determined by aggregating (1) the average days in the period that the energy or service is received and (2) the additional billing period including the payment day.

The aggregate lead days are then weighted by the dollar amount of the billings. Weighted days lead are calculated separately for G1 and Non-G1 customers, by supplier, and are shown in the Confidential Workpapers to the 2023 Study, Schedule DTN-2.

As of May 29, 2024, prior period adjustments made in 2024 related to 2023 were included in the calculation. Prior year adjustments made in 2023 that relate to 2022 were not included in the calculation.

Q. How is the weighted days lead in payment for RECs determined?

A. The weighted days lead in payment for RECs was determined using the same methodology applicable to DS power suppliers described above. In applying this methodology to 2023 RECs, three assumptions were made to reflect actual payment activity towards the Company's 2023 REC commitment. First, the monthly cost of the RECs was assumed to be equivalent to the estimated costs of RECs included in rates in 2023. Second, actual payment activity as of May 29, 2024 towards the Company's 2023 REC commitment was applied in chronological order to the earliest month's estimated cost. Third, a payment date of July 1, 2024 was used for all remaining 2023 REC commitments, which is the last day to obtain 2023 RECs and/or make alternative compliance payments. See Schedule DTN-1, page 21 of 23 for the REC summary related to G1 customers and page 23 of 23 for the REC summary related to Non-G1 customers.

Q. What are the combined weighted days lead in payment of DS purchased power costs and RECs for G1 and Non-G1 customers?

A. The weighted days lead for G1 customers is 75.98 days, as shown on Schedule DTN-1, page 20 of 23. The weighted days lead for Non-G1 customers is 51.19 days, as shown on Schedule DTN-1, page 22 of 23.

Q. How is the total DS and REC lead lag determined?

A. For G1 customers, the DS and REC expense lead of 75.98 days is subtracted from the lag in receipt of revenue of 38.39 days to produce the total DS and REC net lead of 37.59 days. For Non-G1 customers, the DS and REC expense lead of 51.19 days is subtracted from the lag in receipt of revenue of 56.83 days to produce the total DS and REC net lag of 5.64 days. See Schedule DTN-1, page 4 of 23.

Q. How do the results of the 2023 Study compare to the 2022 Study for G1 customers?

A. For G1 customers, the net lead in the 2023 Study of 37.59 days represents an increase of 25.04 days from the net lead in the 2022 Study of 12.55 days. The difference was driven by an increase in total DS and REC expense lead of 20.76 days offset by an overall revenue lag decrease of 4.28 days.

The revenue lag component, "billing to collection" in the 2023 Study is 20.51 days compared to 24.78 days in the 2022 Study, a decrease of 4.27 days. All of the other components in revenue lag net to a total decrease of 0.01 days in the 2023 Study compared to the 2022 Study. The combined change in all of the revenue lag components resulted in an overall revenue lag decrease of 4.28 days.

The DS and REC expense lead is 75.98 days in the 2023 Study compared to 55.22 days in the 2022 Study, a decrease of 6.38 days. In 2023, the DS portion of the expense lead decreased 7.27 weighted days which was driven by a decrease of the average days lead as well as a decrease in the REC portion of total costs compared to the prior year. The REC portion of the expense lead increased 28.03 weighted days which was primarily driven by an increase of the average days lead.

Q. How do the results of the 2023 Study compare to the 2022 Study for Non-G1 customers?

A. For Non-G1 customers, the net lag in the 2023 Study of 5.64 days is 2.99 days more lag than the net lag in the 2022 Study of 2.65 days. The increase in net lag is attributable to a decrease in total DS and REC expense lead of 2.55 days and an increase of overall revenue lag of 0.44 days.

The revenue lag component, "billing to collection" in the 2023 Study is 38.95 days compared to 38.50 days in the 2022 Study, an increase of 0.45 days. All other revenue lag components decreased by of 0.01 days in the 2023 Study compared to the 2022 Study. The net effect of all of the changes in the revenue lag components resulted in a 0.44 day increase in the 2023 revenue lag compared to 2022.

The DS and REC expense lead is 2.55 days lower in 2023 compared to 2022. In 2023, the DS portion of the expense lead decreased 3.78 weighted days which was driven by a decrease of the average days lead. The REC portion of the expense lead increased 1.23 weighted days which was primarily driven by an increase of the average days lead.

Q. How did the Company calculate the Self-Supply net lag days?

A. First the total revenue lag of 56.83 days for Non-G1 customers is computed by adding the number of days associated with each of the four revenue lag components described above. This total number of lag days represents the amount of time between the recorded delivery of service to customers and the receipt of the related revenues from customers. See Schedule DTN-3, page 1, line 6. Next, to determine the expense lead period associated with Self-Supply the Company relied on the lead lag study completed in the Company's Massachusetts electric base rate case filing in D.P.U. 23-80. The Self-Supply lag of 8.55 days was calculated based on actual purchase activity during December 2022, which is representative of a normal lag for Self-Supply[1]. As shown in Schedule DTN-3, I have calculated 48.28 net lag days for Self-Supply by taking the Non-G1 revenue lag days of 56.83 less the Self-Supply expense lag days of 8.55 days, resulting in a net Default Service Self-Supply lag of 48.28 days. See Schedule DTN-3, page 1, line 8.

Q. Why did the Company use the Self-Supply lag as presented in its Massachusetts rate case?

A. As the Company has yet to Self-Supply in New Hampshire there is no actual payment activity for the Company to analyze. The Company used the Self-Supply activity at its Massachusett's electric subsidiary as a proxy as the purchase activity in Massachusett's will be nearly identical to that in New Hampshire. The Company will incorporate New Hampshire Self-Supply payment activity in its 2024 lead lag study as it will be available then.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

[1] Refer to Fitchburg Gas & Electric Light Company rate case filing, D.P.U. 23-80, filed on August 17, 2023, Exhibit-CRD-3, Page 120 of 123. https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/17847752

UNITIL ENERGY SYSTEMS, INC.

DEFAULT SERVICE AND RENEWABLE ENERGY CREDITS

LEAD/LAG STUDY

FOR G1 AND NON-G1 CUSTOMERS

2023

REDACTED

Unitil Energy Systems, Inc.
Default Service Costs and Renewable Energy Credits Lead / Lag Study
For the Period January 1, 2023 Through December 31, 2023
Summary of Results

The results of the Unitil Energy Systems, Inc. Default Service ("DS") and Renewable Energy Credits ("RECs") Lead / Lag Study ("Study") indicate a net lead period for DS and REC costs of 37.59 days for G1 Customers and a net lag period of 5.64 days for Non-G1 Customers. The procedures used to develop the Study are as follows:

I. Determination of Revenue Lag Period

The revenue lag period includes four calculations in determining the total lag – receipt of electric service to meter reading, meter reading to recording of accounts receivable, billing to collection, and collection to receipt of available funds.

A. <u>Receipt of Electric Service to Meter Reading</u>
There are 365 days in the test year January through December 2023, including one 28 day month, four 30 day months, and seven 31 day months. The weighted average day delay is 15.21 days between the time a customer receives service until the meter is read. See page 5 of this Study.

B. <u>Meter Reading to Recording of Accounts Receivable</u>
The average delay time from meter reading to recording of accounts receivable is 1.04 days. See pages 6 - 10 of this Study.

C. <u>Billing to Collection</u>
Billing to Collection lag days are determined by dividing accounts receivable sales by daily electric revenues. The daily average revenues are obtained from the monthly electric sales revenues divided by the number of days in the month. This weighted average delay period from Billing to Collection is 20.51 days for G1 customers and 38.95 days for Non-G1 customers. See pages 11 and 12 of this Study.

D. <u>Collection to Receipt of Available Funds</u>
On average, 1.63 days are required for checks deposited at the Company's banks to be considered available funds for banking transaction purposes. See pages 13 - 19 of this Study.

The sum of all revenue lag periods is 38.39 days for G1 customers and 56.83 days for Non-G1 customers. See page 4 of this Study.

Unitil Energy Systems, Inc.
Default Service Costs and Renewable Energy Credits Lead / Lag Study
For the Period January 1, 2023 Through December 31, 2023
Summary of Results

II. Determination of the Expense Lead Period

The expense lead period consists of the lead in payment of DS supplier costs and RECs, and is calculated for the G1 and Non-G1 customer classes based upon the following calculations: lead period, average days lead, weighted cost, days lead and weighted days lead.

A. Lead Period
The lead period is generally based on a montly cycle and consists of (1) the average days in the period that DS purchases were provided or RECs were required; and (2) the billing period from the end of the period up to and including the payment date. See pages 20 through 23 of the Study.

B. Average Days Lead
The bills for each G-1 and Non-G-1 DS supplier are analyzed to determine the days lead. The REC days lead are also analyzed. Average days lead is calculated by multiplying the lead period by the weighted percentage of aggregate costs. The weighted days are then totaled to obtain the average days lead period for DS suppliers and for the RECs. See pages 20 and 22 of this Study.

C. Weighted Cost
The cost of purchasing default service and RECs is divided by the total combined costs to determine a weighted cost. See pages 20 and 22 of this Study.

D. Weighted Days Lead
The weighted cost is multiplied by the average days lead to calculate the weighted days lead, resulting in 75.98 days for G1 customers and 51.19 days for Non-G1 customers. See pages 20 and 22 of this Study.

III. Summary

The results of the Study indicate a net Purchased Power lead period of 37.59 days for G1 customers and net lag period of 5.64 days for Non-G1 customers. See page 4 of this Study.

Unitil Energy Systems, Inc.
Number of Days Delay Between Receipt of Revenue and
Payment of Default Service Costs and Renewable Energy Credits
Based on 2023 Data

Line No.	Descripton	G1 Customers Page Reference	G1 Customers Number of Days Delay	Non-G1 Customers Page Reference	Non-G1 Customers Number of Days Delay
1	Revenue Lag:				
2	Receipt of Electric Service to Meter Reading	5	15.21 days	5	15.21 days
3	Meter Reading to Recording of Accounts Receivable	6 - 10	1.04 days	6 - 10	1.04 days
4	Billing to Collection	11	20.51 days	12	38.95 days
5	Collection to Receipt of Available Funds	13 - 19	1.63 days	13 - 19	1.63 days
6	Subtotal Revenue Lag Days		38.39 days		56.83 days
7	Less: Lead in Payment of Default Service Costs and Renewable Energy Credits	20	75.98 days	22	51.19 days
8	Total Default Service and Renewable Energy Credit Lag (Line 6 Less Line 7)		-37.59 days		5.64 days

REDACTED

Receipt of Electric Service to Meter Reading
Average Days Delay

January 1, 2023 to December 31, 2023 Number of Days

January	31
February	28
March	31
April	30
May	31
June	30
July	31
August	31
September	30
October	31
November	30
December	31

1 28 Day Month	1*28	28
4 30 Day Months	4*30	120
7 31 Day Months	7*31	217
	Total	365 days

365 Days / 12 Months / 2 = 15.21 days

Unitil Energy Systems, Inc
Meter Reading to Recording of
Accounts Receivable

Month	Average Days
January 2023	1.02
February 2023	1.08
March 2023	1.03
April 2023	1.00
May 2023	1.01
June 2023	1.01
July 2023	1.01
August 2023	1.24
September 2023	1.01
October 2023	1.01
November 2023	1.04
December 2023	1.01
Average	1.04

Unitil Energy Systems, Inc.
Meter Reading to Recording of
Accounts Receivable
Monthly Detail

January 2023

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Weighted Days Lag
1	76,447	99.27%	1	0.99
2	205	0.27%	2	0.01
3	200	0.26%	3	0.01
4	60	0.08%	4	0.00
5	33	0.04%	5	0.00
6	35	0.05%	6	0.00
7	11	0.01%	7	0.00
8-14	14	0.02%	11	0.00
Over 14	1	0.00%	14	0.00
Total	77,006	100.00%		1.02

February 2023

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Weighted Days Lag
1	71,708	93.04%	1	0.93
2	5,153	6.69%	2	0.13
3	107	0.14%	3	0.00
4	69	0.09%	4	0.00
5	12	0.02%	5	0.00
6	5	0.01%	6	0.00
7	5	0.01%	7	0.00
8 to 14	12	0.02%	11	0.00
Over 14	-	0.00%	14	-
Total	77,071	100.00%		1.08

March 2023

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	76,717	99.34%	1	0.99
2	117	0.15%	2	0.00
3	97	0.13%	3	0.00
4	70	0.09%	4	0.00
5	15	0.02%	5	0.00
6	40	0.05%	6	0.00
7	57	0.07%	7	0.01
8 to 14	116	0.15%	11	0.02
Over 14	1	0.00%	14	0.00
Total	77,230	100.00%		1.03

Unitil Energy Systems, Inc.
Meter Reading to Recording of
Accounts Receivable
Monthly Detail

April 2023

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	76,698	99.68%	1	1.00
2	190	0.25%	2	0.00
3	31	0.04%	3	0.00
4	14	0.02%	4	0.00
5	1	0.00%	5	0.00
6	3	0.00%	6	0.00
7	2	0.00%	7	0.00
8 to 14	1	0.00%	11	0.00
Over 14	1	0.00%	14	0.00
Total	76,941	100.00%		1.00

May 2023

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	76,533	99.57%	1	1.00
2	200	0.26%	2	0.01
3	72	0.09%	3	0.00
4	18	0.02%	4	0.00
5	16	0.02%	5	0.00
6	5	0.01%	6	0.00
7	2	0.00%	7	0.00
8 to 14	15	0.02%	11	0.00
Over 14	1	0.00%	14	0.00
Total	76,862	100.00%		1.01

June 2023

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	76,483	99.59%	1	1.00
2	235	0.31%	2	0.01
3	55	0.07%	3	0.00
4	5	0.01%	4	0.00
5	1	0.00%	5	0.00
6	8	0.01%	6	0.00
7	-	0.00%	7	-
8 to 14	11	0.01%	11	0.00
Over 14	2	0.00%	14	0.00
Total	76,800	100.00%		1.01

Unitil Energy Systems, Inc.
Meter Reading to Recording of
Accounts Receivable
Monthly Detail

July 2023

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	76,567	99.50%	1	1.00
2	278	0.36%	2	0.01
3	69	0.09%	3	0.00
4	23	0.03%	4	0.00
5	3	0.00%	5	0.00
6	4	0.01%	6	0.00
7	3	0.00%	7	0.00
8 to 14	2	0.00%	11	0.00
Over 14	-	0.00%	14	-
Total	76,949	100.00%		1.01

August 2023

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	60,901	79.16%	1	0.79
2	13,521	17.57%	2	0.35
3	2,457	3.19%	3	0.10
4	31	0.04%	4	0.00
5	7	0.01%	5	0.00
6	4	0.01%	6	0.00
7	4	0.01%	7	0.00
8 to 14	9	0.01%	11	0.00
Over 14	-	0.00%	14	-
Total	76,934	100.00%		1.24

September 2023

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	76,596	99.45%	1	0.99
2	218	0.28%	2	0.01
3	64	0.08%	3	0.00
4	70	0.09%	4	0.00
5	38	0.05%	5	0.00
6	8	0.01%	6	0.00
7	5	0.01%	7	0.00
8 to 14	22	0.03%	11	0.00
Over 14	-	0.00%	14	-
Total	77,021	100.00%		1.01

Unitil Energy Systems, Inc.
Meter Reading to Recording of
Accounts Receivable
Monthly Detail

October 2023

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	76,686	99.38%	1	0.99
2	296	0.38%	2	0.01
3	125	0.16%	3	0.00
4	20	0.03%	4	0.00
5	13	0.02%	5	0.00
6	1	0.00%	6	0.00
7	6	0.01%	7	0.00
8 to 14	15	0.02%	11	0.00
Over 14	1	0.00%	14	0.00
Total	77,163	100.00%		1.01

November 2023

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	74,724	97.00%	1	0.97
2	2,030	2.64%	2	0.05
3	86	0.11%	3	0.00
4	53	0.07%	4	0.00
5	51	0.07%	5	0.00
6	36	0.05%	6	0.00
7	8	0.01%	7	0.00
8 to 14	45	0.06%	11	0.01
Over 14	-	0.00%	14	-
Total	77,033	100.00%		1.04

December 2023

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	76,660	99.33%	1	0.99
2	254	0.33%	2	0.01
3	123	0.16%	3	0.00
4	90	0	4	0.00
5	4	0.01%	5	0.00
6	12	0.02%	6	0.00
7	7	0.01%	7	0.00
8 to 14	25	0.03%	11	0.00
Over 14	1	0.00%	14	0.00
Total	77,176	100.00%		1.01

REDACTED

Unitil Energy Systems, Inc. Number Of Days Lag In Billing To Collection Twelve Months Average 1/23 - 12/23 G1 Customers				
Month	Days in Month	Electric Sales Revenues	Daily Average (1/Days)	Accounts Receivable Electric Sales
		(1)	(2)	(3)
2023				
January	31	2,878,641	92,859	1,930,100
February	28	2,677,918	95,640	1,990,456
March	31	2,651,394	85,529	1,805,750
April	30	2,563,124	85,437	2,030,104
May	31	2,592,856	83,641	1,844,495
June	30	2,608,627	86,954	1,804,081
July	31	2,975,998	96,000	1,954,236
August	31	3,368,762	108,670	2,276,120
September	30	3,528,654	117,622	2,265,886
October	31	3,303,786	106,574	1,954,687
Novemeber	30	3,039,474	101,316	1,872,756
December	31	2,969,163	95,779	1,977,563
Total		35,158,398	1,156,021	23,706,232
Average		2,929,867	96,335	1,975,519
Payment Lag Days (3/2)				20.51

Unitil Energy Systems, Inc. Number Of Days Lag In Billing To Collection Twelve Months Average 1/23 - 12/23 Non-G1 Customers				
Month	Days in Month	Electric Sales Revenues	Daily Average (1/Days)	Accounts Receivable Electric Sales
		(1)	(2)	(3)
2023				
January	31	24,121,975	778,128	26,001,031
February	28	23,296,735	832,026	28,396,551
March	31	21,570,602	695,826	27,422,826
April	30	18,276,234	609,208	25,223,260
May	31	17,511,880	564,899	23,676,609
June	30	17,723,803	590,793	22,767,842
July	31	23,784,791	767,251	28,951,178
August	31	21,290,206	686,781	26,795,296
September	30	17,127,679	570,923	23,845,328
October	31	14,465,505	466,629	19,966,674
Novemeber	30	14,231,013	474,367	19,620,226
December	31	16,038,626	517,375	21,602,761
Total		$ 229,439,047	$ 7,554,207	$ 294,269,582
Average		$ 19,119,921	$ 629,517	$ 24,522,465
Payment Lag Days (3/2)				38.95

Unitil Energy Systems, Inc.
Collection to Receipt of Available Funds

Revenue Classification by Bank

Revenue is deposited into the remittance account on the day that the revenue is recorded as received.
The following day, the bank statement reflects the prior day's bank availability of funds.

Total Lag Days from Receipt of Funds to Notification of Availability of Funds 1.00 day

Availability of Funds as reported on suceeding business day.
Source: Report on Previous Day Data, Citizens Bank

	Percent of Funds				Weighted Lag Days		
2023	Available Same Day 0 Days Lag	1 Day Float 1 Day Lag	2-Day Float 2 Days Lag	Total	1 Day	2 Days	Total
January	40%	57%	4%	100%	0.57	0.08	0.64
February	43%	53%	4%	100%	0.53	0.08	0.61
March	41%	53%	5%	100%	0.53	0.11	0.64
April	44%	52%	4%	100%	0.52	0.07	0.60
May	39%	55%	6%	100%	0.55	0.13	0.68
June	43%	52%	5%	100%	0.52	0.09	0.61
July	41%	54%	5%	100%	0.54	0.10	0.64
August	44%	49%	7%	100%	0.49	0.14	0.63
September	46%	49%	5%	100%	0.49	0.09	0.58
October	39%	56%	5%	100%	0.56	0.11	0.67
November	40%	53%	6%	100%	0.53	0.13	0.66
December	42%	53%	6%	100%	0.53	0.11	0.64

Average Weighted Lag Days for Availability of Funds 0.63 days

Summary

Total Lag Days from Receipt of Funds to Notification of Availability of Funds	1.00	day
Average Weighted Lag Days for Availability of Funds	0.63	days
Total Lag Days from Collection to Availability of Funds:	**1.63**	**days**

Unitil Energy Systems, Inc.
Remmitance Accounts

January, 2023	Available Balance	1 Day Float	2 Day Float	Total Available + Float
3	77,786	403,819	11,952	
4	56,881	321,864	11,230	
5	693,313	351,782	29,636	
6	3,556	315,349	36,620	
9	325,419	616,752	45,475	
10	771,055	353,106	31,373	
11	239,440	246,141	20,421	
12	4,502	252,042	6,752	
13	12,194	417,276	10,140	
17	49,154	577,209	10,236	
18	1,281,422	131,152	7,188	
19	68,516	379,406	14,442	
20	9,554	200,454	14,492	
23	44,912	442,045	30,670	
24	683,622	72,612	16,303	
25	1,840	165,712	10,910	
26	81,134	110,508	8,036	
27	21,046	177,211	33,766	
30	25,046	610,343	48,453	
31	7,238	231,842	40,428	
	4,457,633	6,376,625	438,523	11,272,781
% of Available Funds	40%	57%	4%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.57	0.08	0.64

February, 2023	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	29,588	271,670	23,747	
2	43,717	326,936	13,287	
3	45,651	256,764	14,839	
6	462,348	837,963	45,451	
7	1,148,236	464,355	15,979	
8	403,679	770,981	20,357	
9	24,735	272,630	18,874	
10	24,649	665,870	14,657	
13	438,516	690,029	35,518	
14	1,237,563	241,830	17,776	
15	606,215	189,705	14,910	
16	22,834	192,426	6,583	
17	58,454	458,286	2,828	
21	58,256	405,142	171,241	
22	1,022,148	183,284	12,211	
23	29,004	231,946	13,949	
24	5,387	118,620	13,597	
27	257,413	347,980	51,423	
28	(36,304)	369,039	41,026	
	5,882,088	7,295,456	548,253	13,725,797
% of Available Funds	43%	53%	4%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.53	0.08	0.61

Unitil Energy Systems, Inc.
Remmitance Accounts

March, 2023	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	33,135	318,218	76,717	
2	(32,329)	252,048	16,856	
3	34,173	224,694	31,129	
6	73,124	574,138	22,600	
7	745,091	229,308	215,868	
8	244,216	607,109	72,267	
9	24,066	696,636	29,143	
10	17,602	303,105	17,673	
13	371,464	662,482	34,504	
14	1,133,623	756,327	83,159	
15	264,073	363,428	20,329	
16	62,062	126,064	9,156	
17	44,003	294,610	3,024	
20	92,408	410,783	6,027	
21	1,834,824	38,924	10,013	
22	340,427	373,758	25,578	
23	(7,330)	200,035	5,630	
24	18,161	124,957	4,384	
27	470,016	358,163	26,106	
28	419,870	97,783	41,651	
29	33,485	517,456	30,687	
30	1,943	230,555	17,134	
31	16,788	254,586	7,499	
	6,234,893	8,015,167	807,134	15,057,194
% of Available Funds	41%	53%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.53	0.11	0.64

April, 2023	Available Balance	1 Day Float	2 Day Float	Total Available + Float
3	76,950	615,639	39,571	
4	5,913	198,855	41,435	
5	40,365	352,786	30,978	
6	351,135	413,082	43,590	
7	(2,443)	197,972	45,624	
10	363,972	627,983	23,942	
11	1,035,427	364,539	19,675	
12	378,146	497,465	15,261	
13	14,623	535,552	23,567	
14	64,754	230,477	5,919	
17	437,779	378,965	15,839	
18	19,406	366,647	39,096	
19	1,758,181	359,010	44,921	
20	(19,530)	236,890	16,612	
21	6,311	320,611	3,429	
24	281,932	324,991	7,380	
25	898,766	219,418	19,447	
26	234,189	254,529	22,674	
27	22,598	195,792	35,371	
28	(19,746)	332,811	6,388	
	5,948,728	7,024,014	500,719	13,473,461
% of Available Funds	44%	52%	4%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.52	0.07	0.60

Unitil Energy Systems, Inc.
Remmitance Accounts

May, 2023	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	65,886	409,233	15,738	
2	74,828	281,551	19,800	
3	39,205	439,024	13,455	
4	43,275	384,789	60,923	
5	65,886	409,233	15,738	
8	354,737	695,833	28,425	
9	986,758	135,595	11,317	
10	266,059	432,989	104,975	
11	(19,268)	340,071	57,095	
12	(30,452)	330,231	5,790	
15	320,165	575,536	80,053	
16	945,211	449,662	117,654	
17	320,304	368,897	10,975	
18	12,886	120,554	8,498	
19	7,908	61,181	2,426	
22	508,806	408,560	7,190	
23	776,728	78,586	10,131	
24	162,415	144,953	170,930	
25	(142,975)	322,179	18,883	
26	(5,488)	53,077	1,482	
30	261,787	418,618	35,838	
31	(1,205)	213,746	34,373	
	5,013,458	7,074,098	831,689	12,919,245
% of Available Funds	39%	55%	6%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.55	0.13	0.68

June, 2023	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	113,310	261,606	59,666	
2	(5,398)	255,945	25,924	
5	50,953	339,746	27,653	
6	565,776	187,244	12,290	
7	384,873	235,034	22,317	
8	24,766	453,135	42,900	
9	56,838	268,138	55,396	
12	306,386	476,988	38,077	
13	919,528	514,856	20,584	
14	211,951	216,679	32,367	
15	(2,353)	319,977	20,909	
16	(9,428)	420,269	5,881	
20	506,686	412,553	8,059	
21	1,345,009	374,795	2,991	
22	11,232	409,720	15,692	
23	5,197	102,529	11,466	
26	35,018	226,892	13,876	
27	744,623	284,125	37,749	
28	(9,333)	251,080	58,375	
29	17,074	183,741	6,595	
30	25,418	194,576	39,168	
	5,298,125	6,389,628	557,935	12,245,688
% of Available Funds	43%	52%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.52	0.09	0.61

REDACTED

Unitil Energy Systems, Inc.
Remmitance Accounts

July, 2023	Available Balance	1 Day Float	2 Day Float	Total Available + Float
3	84,568	473,604	31,304	
5	26,118	92,723	13,051	
6	463,642	332,923	44,611	
7	62,957	174,387	39,830	
10	389,950	891,772	46,627	
11	880,487	412,843	18,752	
12	405,762	188,031	33,556	
13	(2,166)	209,295	19,549	
14	24,942	392,728	89,911	
17	(13,491)	848,522	26,021	
18	1,123,399	54,038	16,083	
19	450,732	370,172	22,129	
20	(4,988)	326,171	3,440	
21	13,862	101,904	23,801	
24	244,883	372,800	130,299	
25	683,079	464,641	20,502	
26	188,471	221,313	20,652	
27	2,031	222,497	12,462	
28	9,440	92,012	3,919	
31	70,958	400,483	13,191	
Total	5,104,637	6,642,859	629,690	12,377,186
% of Available Funds	41%	54%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.54	0.10	0.64

August, 2023	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	134,709	258,233	81,339	
2	(19,953)	367,615	73,101	
3	(27,038)	290,424	10,706	
4	52,553	180,417	9,595	
7	70,021	333,585	32,031	
8	1,213,492	151,103	19,387	
9	629,331	553,400	142,132	
10	(94,172)	424,464	34,572	
11	(13,406)	635,978	48,833	
14	361,844	551,821	48,388	
15	1,218,654	452,809	16,344	
16	677,257	461,169	11,487	
17	34,443	380,952	68,835	
18	(69,851)	111,639	68,170	
21	474,278	421,531	13,904	
22	1,203,118	188,520	24,464	
23	387,482	168,466	22,956	
24	(3,301)	192,720	15,516	
25	16,089	162,202	137,992	
28	155,913	505,681	54,038	
29	231,750	218,775	53,047	
30	88,317	299,484	13,789	
31	11,436	185,158	63,968	
Total	6,732,966	7,496,146	1,064,594	15,293,706
% of Available Funds	44%	49%	7%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.49	0.14	0.63

REDACTED

Unitil Energy Systems, Inc.
Remmitance Accounts

September, 2023	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	2,376	416,778	23,756	
5	64,392	612,489	44,624	
6	104,356	446,815	54,756	
7	655,214	294,983	66,201	
8	(10,506)	330,934	18,008	
11	656,766	457,054	18,994	
12	1,265,568	327,353	15,664	
13	471,438	620,455	21,398	
14	8,025	420,590	13,941	
15	22,936	212,882	5,455	
18	288,550	324,720	11,486	
19	1,714,037	339,187	178,044	
20	77,934	335,419	30,779	
21	(3,063)	187,287	8,205	
22	26,758	218,858	3,602	
25	996,847	530,011	24,703	
26	47,458	183,935	28,181	
27	1,729	250,382	13,599	
28	12,051	150,603	10,345	
29	18,984	132,145	48,166	
	6,421,849	6,792,880	639,907	13,854,636
% of Available Funds	46%	49%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.49	0.09	0.58

October, 2023	Available Balance	1 Day Float	2 Day Float	Total Available + Float
2	44,005	332,495	28,372	
3	59,439	654,100	38,812	
4	18,965	246,630	65,664	
5	288,711	697,293	40,739	
6	(6,149)	411,214	25,724	
10	86,253	554,177	27,422	
11	1,248,393	300,731	40,036	
12	37,230	146,042	41,839	
13	40,035	376,641	37,949	
16	340,157	201,806	7,958	
17	1,182,433	611,908	155,638	
18	294,489	858,751	10,898	
19	32,645	267,788	24,973	
20	(10,687)	97,251	18,036	
23	227,429	447,787	6,471	
24	720,380	66,970	5,810	
25	179,486	134,994	7,703	
26	13,862	82,672	7,761	
27	7,339	206,969	27,888	
30	47,899	272,860	35,902	
31	112,827	167,366	28,981	
	4,965,140	7,136,445	684,576	12,786,161
% of Available Funds	39%	56%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.56	0.11	0.67

REDACTED

Unitil Energy Systems, Inc.
Remmitance Accounts

November, 2023	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	117,437	239,296	173,775	
2	(144,738)	399,821	46,417	
3	(24,856)	156,856	10,001	
6	79,733	503,508	16,130	
7	778,135	193,294	42,369	
8	261,812	281,892	38,821	
9	(16,219)	542,233	15,210	
10	97,894	407,025	9,356	
13	40,705	432,525	32,239	
14	1,077,338	386,522	80,125	
15	294,040	331,563	17,157	
16	(3,685)	185,427	5,179	
17	8,154	224,893	2,780	
20	432,721	186,553	4,999	
21	758,182	98,681	5,448	
22	323,796	276,481	88,325	
24	(69,335)	284,087	9,381	
27	45,514	163,768	15,660	
28	338,887	135,125	9,759	
29	64,236	293,044	3,115	
30	30,230	214,567	69,175	
	4,489,980	5,937,161	695,421	11,122,562
% of Available Funds	40%	53%	6%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.53	0.13	0.66

December, 2023	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	(52,593)	151,122	20,229	
4	80,491	388,785	18,579	
5	(7,428)	87,693	193,658	
6	486,665	397,305	73,433	
7	(28,108)	179,716	30,485	
8	1,734	375,199	24,564	
11	351,598	634,130	12,966	
12	795,937	269,369	8,142	
13	239,945	232,368	8,250	
14	27,866	421,578	26,871	
15	(9,615)	316,198	14,124	
18	351,530	273,995	32,684	
19	835,651	304,345	12,958	
20	12,673	164,142	1,943	
21	12,919	152,584	20,005	
22	757	292,926	11,399	
26	225,461	309,814	6,998	
27	1,045,330	241,628	30,424	
28	(4,085)	205,861	13,838	
29	15,100	140,480	17,544	
	4,381,827	5,539,238	579,094	10,500,159
% of Available Funds	42%	53%	6%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.53	0.11	0.64

UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF DEFAULT SERVICE COSTS AND RENEWABLE ENERGY CREDITS

	Reference Page		Cost	% of Total	Average Days Lead	Weighted Days Lead
G1 Default Service Supplier Costs	Schedule DTN-2	$	2,790,798	86.68%	34.05 days	29.52 days
G1 Renewable Energy Credits	21	$	428,678	13.32%	348.95 days	46.46 days
Total		$	3,219,476	100.00%		75.98 days

REDACTED

UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF RENEWABLE ENERGY CREDITS

G1	2023												
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
RECs*													
Period Begin	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	
Period End	1/31/2023	2/28/2023	3/31/2023	4/30/2023	5/31/2023	6/30/2023	7/31/2023	8/31/2023	9/30/2023	10/31/2023	11/30/2023	12/31/2023	
$ Amount	$35,624	$34,763	$34,741	$33,115	$35,191	$35,835	$39,587	$41,948	$36,634	$35,139	$31,870	$34,230	
REC Purchase Applied	($34,518)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net $ Amount	$1,106	$34,763	$34,741	$33,115	$35,191	$35,835	$39,587	$41,948	$36,634	$35,139	$31,870	$34,230	$394,160
% to Total	0.26%	8.11%	8.10%	7.72%	8.21%	8.36%	9.23%	9.79%	8.55%	8.20%	7.43%	7.98%	91.95%
Payment Date**	7/1/2024	7/1/2024	7/1/2024	7/1/2024	7/1/2024	7/1/2024	7/1/2024	7/1/2024	7/1/2024	7/1/2024	7/1/2024	7/1/2024	
Lead Period	532.50	503.00	473.50	443.00	412.50	382.00	351.50	320.50	290.00	259.50	229.00	198.50	
Weighted Days	1.37	40.79	38.37	34.22	33.86	31.93	32.46	31.36	24.78	21.27	17.02	15.85	323.28 days
REC Purchases***													
Period Begin	1/1/2023	1/1/2023	1/1/2023	1/1/2023									
Period End	1/31/2023	1/31/2023	1/31/2023	1/31/2023									
$ Amount	$2,332	$11,211	$4,548	$16,427									$34,518
% to Total	0.54%	2.62%	1.06%	3.83%									8.05%
Payment Date	8/16/2023	8/24/2023	11/21/2023	2/23/2024									
Lead Period	212.50	220.50	309.50	403.50									
Weighted Days	1.16	5.77	3.28	15.46									25.67 days
Total $ Amount													$428,678

Weighted Days 348.95 days

* Estimated cost of RECs included in rates in 2023
** The last day to acquire 2023 Renewable Energy Credits and/or make alternative compliance payments is July 1, 2024
*** Actual purchasing activity for 2023 RECs applied in chronological order to estimated cost of RECs included in rates in 2023

UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF DEFAULT SERVICE COSTS AND RENEWABLE ENERGY CREDITS

	Reference Page	Cost	% of Total	Average Days Lead	Weighted Days Lead
Non-G1 Default Service Supplier Costs	Schedule DTN-2	$ 96,508,695	94.86%	35.01 days	33.21 days
Non-G1 Renewable Energy Credits	23	$ 5,228,250	5.14%	349.83 days	17.98 days
Total		$ 101,736,945	100.00%		51.19 days

UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF RENEWABLE ENERGY CREDITS

NON-G1	2023												
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
RECs*													
Period Begin	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	
Period End	1/31/2023	2/28/2023	3/31/2023	4/30/2023	5/31/2023	6/30/2023	7/31/2023	8/31/2023	9/30/2023	10/31/2023	11/30/2023	12/31/2023	
$ Amount	$476,679	$473,945	$428,992	$383,110	$365,255	$371,830	$468,085	$566,451	$444,754	$391,446	$391,127	$466,578	
REC Purchase Applied	($407,317)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net $ Amount	$69,362	$473,945	$428,992	$383,110	$365,255	$371,830	$468,085	$566,451	$444,754	$391,446	$391,127	$466,578	$4,820,933
% to Total	1.33%	9.07%	8.21%	7.33%	6.99%	7.11%	8.95%	10.83%	8.51%	7.49%	7.48%	8.92%	92.21%
Payment Date**	7/1/2024	7/1/2024	7/1/2024	7/1/2024	7/1/2024	7/1/2024	7/1/2024	7/1/2024	7/1/2024	7/1/2024	7/1/2024	7/1/2024	
Lead Period	532.50	503.00	473.50	443.00	412.50	382.00	351.50	320.50	290.00	259.50	229.00	198.50	
Weighted Days	7.06	45.60	38.85	32.46	28.82	27.17	31.47	34.72	24.67	19.43	17.13	17.71	325.09 days
REC Purchases***													
Period Begin	1/1/2023	1/1/2023	1/1/2023	1/1/2023									
Period End	1/31/2023	1/31/2023	1/31/2023	1/31/2023									
$ Amount	$27,948	$134,389	$54,522	$190,458									$407,317
% to Total	0.53%	2.57%	1.04%	3.64%									7.79%
Payment Date	8/16/2023	8/24/2023	11/21/2023	2/23/2024									
Lead Period	212.50	220.50	309.50	403.50									
Weighted Days	1.14	5.67	3.23	14.70									24.74 days
Total $ Amount													$5,228,250

Weighted Days 349.83 days

* Estimated cost of RECs included in rates in 2023
** The last day to acquire 2023 Renewable Energy Credits and/or make alternative compliance payments is July 1, 2024
*** Actual purchasing activity for 2023 RECs applied in chronological order to estimated cost of RECs included in rates in 2023

UNITIL ENERGY SYSTEMS, INC.

REDACTED WORKPAPERS

FOR THE

DEFAULT SERVICE AND RENEWABLE ENERGY CREDITS

LEAD/LAG STUDY

FOR G1 AND NON-G1 CUSTOMERS

2023

REDACTED

UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF DEFAULT SERVICE COSTS AND RENEWABLE ENERGY CREDITS

	Reference Page	Cost	% of Total	Average Days Lead	Weighted Days Lead
Summary					
Total G1 Default Service Supplier Costs	Detail below	$ 2,790,798	86.68%	34.05 days	29.52 days
G1 Renewable Energy Credits	Schedule DTN-1 p 21	$ 428,678	13.32%	348.95 days	46.46 days
Total		$ 3,219,476	100.00%		75.98 days
Detail for G1 Default Service Supplier Costs					
Supplier A	3	$ 417,724	14.97%	[redacted]	
Supplier B	4	$ 2,373,074	85.03%		
Total G1 Default Service Supplier Costs		$ 2,790,798	100.00%		34.05 days

REDACTED
UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF ELECTRIC COSTS

DS SERVICE POWER SUPPLY CONTRACTS

G1 SUPPLIERS	MONTH ENERGY PURCHASES DELIVERED 2023 JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Supplier A													
Normal Service													
Period Begin								8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	
Period End								8/31/2023	9/30/2023	10/31/2023	11/30/2023	12/31/2023	
$ Amount								$ 183,956	$ 105,843	$ 68,366	$ 96,074	$ 115,072	$ 569,311
% to Total								44.04%	25.34%	16.37%	23.00%	27.55%	136.29%
Payment Date								[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Lead Period								[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Weighted Days								[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Prior Period Adjustments (shown in billing period in 2023)													
Period Begin								8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	
Period End								8/31/2023	9/30/2023	10/31/2023	11/30/2023	12/31/2023	
$ Amount								$ (100,215)	$ (18,018)	$ (1,851)	$ (15,508)	$ (15,995)	$ (151,587)
% to Total								-23.99%	-4.31%	-0.44%	-3.71%	-3.83%	-36.29%
Payment Date								[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Lead Period								[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Weighted Days								[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total $ Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 83,741	$ 87,824	$ 66,514	$ 80,566	$ 99,077	$ 417,724
Weighted Days													[redacted]

REDACTED
UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF ELECTRIC COSTS

DS SERVICE POWER SUPPLY CONTRACTS

G1 SUPPLIERS	MONTH ENERGY PURCHASES DELIVERED 2023												
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Supplier B													
Normal Service													
Period Begin	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023						
Period End	1/31/2023	2/28/2023	3/31/2023	4/30/2023	5/31/2023	6/30/2023	7/31/2023						
$ Amount	$ 411,968	$ 451,949	$ 314,527	$ 279,225	$ 271,855	$ 325,938	$ 388,630						$ 2,444,092
% to Total	17.36%	19.04%	13.25%	11.77%	11.46%	13.73%	16.38%						102.99%
Payment Date	[redacted]												
Lead Period													
Weighted Days													[redacted]
Prior Period Adjustments (shown in billing period in 2023)													
Period Begin	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023						
Period End	1/31/2023	2/28/2023	3/31/2023	4/30/2023	5/31/2023	6/30/2023	7/31/2023						
$ Amount	$ 2,942	$ 8,219	$ (3,859)	$ 1,705	$ (4,218)	$ 4,646	$ (80,453)						$ (71,018)
% to Total	0.12%	0.35%	-0.16%	0.07%	-0.18%	0.20%	-3.39%						-2.99%
Payment Date	[redacted]												
Lead Period													
Weighted Days													[redacted]
Total $ Amount	$ 414,910	$ 460,168	$ 310,668	$ 280,930	$ 267,637	$ 330,583	$ 308,176	$ -	$ -	$ -	$ -	$ -	$ 2,373,074
Weighted Days													[redacted]

REDACTED

UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF DEFAULT SERVICE COSTS AND RENEWABLE ENERGY CREDITS

	Reference Page	Cost	% of Total	Average Days Lead	Weighted Days Lead
Summary					
Total Non-G1 Default Service Supplier Costs	see below	$ 96,508,695	94.86%	35.01 days	33.21 days
Renewable Energy Credits	Schedule DTN-1 p 23	$ 5,228,250	5.14%	349.83 days	17.98 days
Total		$ 101,736,945	100.00%		51.19 days
Detail for Non-G1 Default Service Supplier Costs					
Supplier C	6	$ 19,890,344	20.61%	[redacted]	
Supplier D	7	$ 76,618,351	79.39%		
Total Non-G1 Default Service Supplier Costs		$ 96,508,695	100.00%		35.01 days

REDACTED

UNITIL ENERGY SYSTEMS, INC

LEAD IN PAYMENT OF ELECTRIC COSTS

DS SERVICE POWER SUPPLY CONTRACTS

NON-G1 SUPPLIERS	MONTH ENERGY PURCHASES DELIVERED 2023												
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Supplier C													
Normal Service													
Period Begin								8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	
Period End								8/31/2023	9/30/2023	10/31/2023	11/30/2023	12/31/2023	
$ Amount								$ 3,645,017	$ 2,580,637	$ 2,045,819	$ 3,514,177	$ 7,823,352	$ 19,609,002
% to Total								18.33%	12.97%	10.29%	17.67%	39.33%	98.59%
Payment Date								[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Lead Period								[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Weighted Days								[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Prior Period Adjustments (shown in billing period in 2023)													
Period Begin								8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	
Period End								8/31/2023	9/30/2023	10/31/2023	11/30/2023	12/31/2023	
$ Amount								$ 40,442	$ (24,721)	$ (27,638)	$ 67,484	$ 225,776	$ 281,342
% to Total								0.20%	-0.12%	-0.14%	0.34%	1.14%	1.41%
Payment Date								[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Lead Period								[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Weighted Days								[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total $ Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,685,459	$ 2,555,915	$ 2,018,181	$ 3,581,661	$ 8,049,129	$ 19,890,344
Weighted Days													[redacted]

REDACTED
UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF ELECTRIC COSTS

DS SERVICE POWER SUPPLY CONTRACTS

	MONTH ENERGY PURCHASES DELIVERED												
NON-G1	**2023**												
SUPPLIERS	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Supplier D													
Normal Service													
Period Begin	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023						
Period End	1/31/2023	2/28/2023	3/31/2023	4/30/2023	5/31/2023	6/30/2023	7/31/2023						
$ Amount	$ 22,067,018	$ 19,034,388	$ 11,337,469	$ 6,181,493	$ 5,473,861	$ 5,320,589	$ 8,382,224						$ 77,797,041
% to Total	28.80%	24.84%	14.80%	8.07%	7.14%	6.94%	10.94%						101.54%
Payment Date	[redacted]												
Lead Period													
Weighted Days													[redacted]
Prior Period Adjustments													
(shown in billing period in 2023)													
Period Begin	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023						
Period End	1/31/2023	2/28/2023	3/31/2023	4/30/2023	5/31/2023	6/30/2023	7/31/2023						
$ Amount	$ (447,457)	$ (232,979)	$ (7,772)	$ (102,141)	$ (358,768)	$ (87,976)	$ 58,403						$ (1,178,690)
% to Total	-0.58%	-0.30%	-0.01%	-0.13%	-0.47%	-0.11%	0.08%						-1.54%
Payment Date	[redacted]												
Lead Period													
Weighted Days													[redacted]
Total $ Amount	$ 21,619,560	$ 18,801,409	$ 11,329,697	$ 6,079,352	$ 5,115,092	$ 5,232,613	$ 8,440,627	$ -	$ -	$ -	$ -	$ -	$ 76,618,351
Weighted Days													[redacted]

Unitil Energy Systems, Inc.
Number of Days Delay Between Receipt of Revenue and
Payment of Default Service Self-Supply Costs

Line No.	Descripton	Non-G1 Customers Sch. DTN-1 Page Reference	Number of Days Delay
1	Revenue Lag:		
2	Receipt of Electric Service to Meter Reading	5	15.21 days
3	Meter Reading to Recording of Accounts Receivable	6 - 10	1.04 days
4	Billing to Collection	12	38.95 days
5	Collection to Receipt of Available Funds	13 - 19	1.63 days
6	Subtotal Revenue Lag Days		56.83 days
7	Less: Lead in Payment of Default Service Self-Supply Costs [1]		8.55 days
8	Total Default Service Self-Supply Lag (Line 6 Less Line 7)		48.28 days

Notes:
(1) Per Fitchburg Gas & Electric Light Rate Case Filing D.P.U. 23-80 Exhibit-CRD-3, Page 120 of 123
https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/17847752