Unitil Energy Systems, Inc
Default Service Tariffs
March 12, 2010
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Unitil
Unitil Service Corp.

March 12, 2010

BY HAND-DELIVERY

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 S. Fruit St, Suite 10
Concord, N.H. 03301-2429

Re: PETITION FOR APPROVAL OF DEFAULT SERVICE SOLICITATION AND PROPOSED DEFAULT SERVICE TARIFF

Docket No. DE 10-028

Dear Secretary Howland:

On behalf of Unitil Energy Systems, Inc. ("UES"), enclosed please find an original and six (6) copies of "Petition for Approval of Default Service Solicitation and Proposed Default Service Tariff." The Petition requests that the New Hampshire Public Utilities Commission ("Commission") approve UES' solicitation and procurement, for the three month period beginning May 1, 2010, of 100 percent of its Default Service ("DS") requirements for its G1 customers, and for twenty-five percent of Non-G1 supplies for a two-year period also beginning May 1, 2010, and approve the proposed tariff incorporating the results of this solicitation into rates.

In support of the Petition, the filing includes the pre-filed direct testimony and schedules of:

1. Robert S. Furino, Director of Energy Contracts, Unitil Service Corp.
2. Linda S. McNamara, Senior Regulatory Analyst I, Unitil Service Corp.
3. David L. Chong, Director of Finance, Unitil Service Corp.

An original and six (6) copies of UES' Motion for Confidentiality and Protective Order are also enclosed. The Confidential portions of this filing have been removed, and the original and six (6) copies of these sections are enclosed in sealed and marked envelopes.

An electronic copy of the non-confidential version filing is being provided to the Commission, Commission Staff and the Office of Consumer Advocate ("OCA") as required by N.H. Code Admin. Pro. Puc 203.03.

Gary M. Epler
Chief Regulatory Attorney
6 Liberty Lane West
Hampton, NH 03842-1720

Phone: 603-773-6440
Fax: 603-773-6640
Email: epler@unitil.com

Thank you for your attention to this matter.

Sincerely,

Gary Epler
Attorney for Unitil Energy Systems, Inc.

Enclosure

cc: Suzanne Amidon, Staff Attorney (with Confidential material)
Meredith Hatfield, Consumer Advocate (with Confidential material)

BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

	)	
	)	
UNITIL ENERGY SYSTEMS, INC.	)	**DOCKET NO. DE 10-028**
Petitioner	)	
	)	

PETITION FOR APPROVAL OF DEFAULT SERVICE SOLICITATION AND PROPOSED DEFAULT SERVICE TARIFF

Unitil Energy Systems, Inc., ("UES" or "Company") submits this Petition requesting:

1) approval of the New Hampshire Public Utilities Commission ("Commission") of UES' solicitation and procurement of two contracts for Default Service ("DS"). The first contract is for 100 percent of large customer (G1) default service requirements for three months in duration, May 1, 2010, through July 31, 2010; the second contract is for 25 percent of small customer (non-G1) default service requirements for 24 months in duration, May 1, 2010 through April 30, 2012; and

2) approval of proposed tariffs incorporating the results of this solicitation into rates. As part of this request, and as discussed more fully below, UES seeks a final order granting the approvals requested herein no later than March 19, 2010. In support of its Petition, UES states the following:

Petitioner

UES is a New Hampshire corporation and public utility primarily engaged in the distribution of electricity in the capital and seacoast regions of New Hampshire.

Background

Pursuant to the terms of the Settlement Agreement, and as approved by the Commission in NHPUC Order No. 24,511, UES has solicited for DS power supplies for three contracts: the three month period beginning May 1, 2010, for one hundred (100) percent of its DS supply requirements for its G1 customers; and the 24 month period beginning May 1, 2010 for 25 percent of its default service requirements for its non-G1 customers. The solicitation process was conducted in accordance with the model schedule contained in the Settlement Agreement.

UES submits this Petition in compliance with the Settlement Agreement and orders issued in Docket No. DE 05-064 and subsequent related proceedings, and requests approval of the results of its most recent solicitation, as described more fully below and in the attached exhibits, and also requests approval of the tariffs included with this filing.

Description of Exhibits

Attached to this Petition are the following Exhibits:

Exhibit RSF-1: Testimony and Schedules of Robert S. Furino.

Exhibit LSM-1: Testimony and Schedules of Linda S. McNamara.

Exhibit DC-1: Testimony and Schedules of David L. Chong.

Solicitation Process and Selection of Winning Bidders

UES submits that it has conducted the solicitation process, made its selection of the winning bidder and entered into a Power Supply Agreement in accordance with the representations set forth in its Petition submitted on April 1, 2005, as amended by the Settlement Agreement filed on August 11, 2005 and as approved by the Commission in its orders in Docket No. DE 05-064 and subsequent related dockets. Details of UES' compliance in this regard are set forth in Exhibit RSF-1 and the Bid Evaluation Report attached as Schedule RSF-1 thereto. A copy of the RFP, redlined against the previous RFP issued by UES in this docket, was provided to Commission Staff and the Office of Consumer Advocate ("OCA") by e-mail on February 2, 2010. A redline version of the final Power Supply Agreement with the winning bidder is provided in the confidential attachment labeled Tab A to Schedule RSF-1.

Proposed Tariffs

UES' proposed tariffs are included with this filing and are provided in redline as Schedule LSM-1 attached to Exhibit LSM-1. UES requests approval of these proposed tariffs.

Updated Lead Lag Study

Also included in this filing is an updated lead/lag study ("2009 UES Default Service and Renewable Energy Credits Lead Lag Study"). Pursuant to the Settlement Agreement approved by the Commission in Docket DE 05-064, UES' internal administrative costs and supply-related working capital costs, based on actual supply costs and an agreed upon lead/lag study or its equivalent, are recovered through DS rates on a fully reconciling basis. This 2009 Lead Lag Study incorporates changes agreed to by UES and the Commission Staff and reflected in the settlement letter dated July 16, 2009 filed in Docket No. DE 09-009, and approved by the Commission in Order No. 25,011, issued September 4, 2009. UES recognizes, however, that the Commission, Staff and interested parties such as the OCA, may not have a sufficient opportunity to review the updated lead/lag study within the time frame that UES is requesting approval of the tariffs. Accordingly, UES requests approval of the proposed tariffs as filed, subject to further investigation and review of the lead/lag study and subject to reconciliation, if necessary.

Proposed Rate Calculations

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. Schedule LSM-4, Page 1, shows the proposed G1 Variable Power Supply Charges and Schedule LSM-5, Page 1, shows the proposed G1 Variable RPS Charge.
All schedules are attached to Exhibit LSM-1.

Bill Impacts

Schedule LSM-6 provides typical bill impacts associated with UES' proposed DS rate changes for customers who do not choose a competitive supplier.

Motion for Confidential Treatment

Accompanying this Petition is a Motion for Confidential Treatment and Protective Order wherein UES seeks protective treatment with respect to certain information contained in Exhibit RSF-1, Exhibit LSM-1, and Exhibit DC-1 and in the e-mails exchanged with the Staff and the OCA on March 12, 2010 containing the confidential material.

Request for Approvals

UES respectfully requests that the Commission issue a final order no later than March 19, 2010, containing the following findings of fact, conclusions and approvals:

1. FIND that UES has followed the solicitation process approved by the Commission;

2. FIND that UES' analysis of the bids submitted was reasonable;

3. FIND that UES has supplied a reasonable rationale for its choice of supplier.

4. CONCLUDE that, based upon the above Findings, the power supply costs resulting from the solicitation are reasonable;

5. CONCLUDE that, based upon the above Findings and Conclusion that the power supply costs resulting from the solicitation are reasonable, and subject to the ongoing obligation of UES to act prudently, according to law and in conformity with Commission orders, the amounts payable to the seller for power supply costs under the power supply agreements for G1 and non-G1 customers are approved for inclusion in retail rates beginning May 1, 2010.

6. GRANT APPROVAL of the tariff changes requested herein.

7. GRANT APPROVAL of the Motion for Confidential Treatment and Protective Order.

8. GRANT APPROVAL of the 2009 UES Default Service and Renewable Energy Credits Lead Lag Study, subject to further review and investigation if necessary.

Conclusion

For all of the foregoing reasons, UES requests that the Commission grant it the approvals requested in this Petition, and for such other relief as the Commission may deem necessary and proper.

Respectfully submitted,

UNITIL ENERGY SYSTEMS, INC.
By its Attorney:

Gary Epler
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March 12, 2010

STATE OF NEW HAMPSHIRE
BEFORE THE PUBLIC UTILITIES COMMISSION

PETITION FOR APPROVAL OF DEFAULT SERVICE SOLICITATION **UNITIL ENERGY SYSTEMS, INC.** **Petitioner**	)	**DOCKET NO. DE 10-028**

MOTION FOR CONFIDENTIAL TREATMENT

AND PROTECTIVE ORDER

Unitil Energy Systems, Inc. ("UES" or the "Company") respectfully requests that the New Hampshire Public Utilities Commission (the "Commission") grant a protective order for certain confidential information contained in the Company's "Petition for Approval of Default Service Solicitation and Proposed Default Service Tariff" ("Petition"), consistent with R.S.A. 91-A:5(IV) and N.H. Admin. Rules, Puc 203.08. Specifically, UES requests that the Commission issue an order requiring confidential treatment for:

(a) The material contained in Tab A of Schedule RSF-1 which is attached to Exhibit RSF-1 (with the exception of the name of the winning bidders, TransCanada Power Marketing Ltd., as the supplier for the 24-month Non-G1 supply requirements, and Hess Corporation as the supplier for the 3-month G1 supply Requirement.);

(b) The "Total G1 Class DS Suppler Charges," "Working Capital Requirement," "Supply Related Working Capital," and "Provision for Uncollected Accounts," found on columns (a), (d), (f) and (l) of Page 3 and columns (a), (d), (f) and (g) of

Page 5 of Schedule LSM-4. As discussed in paragraph no. 4, below, UES is seeking protective treatment of this information for only a limited period of time.

(c) The "Payment Date," "Lead Period" and "Weighted Days" information contained in Schedule DC-2 which is attached to Exhibit DC-1.

(d) UES is also seeking protective treatment of confidential information provided to the Staff and OCA by e-mail on March 12, 2009.

In support of this motion, UES states as follows:

1. In its Petition, UES seeks Commission approval of the results of the Default Service solicitation, and approval of Proposed Default Service Tariffs for G1 and non-G-1 customers beginning May 1, 2010. As required by Order No. 24,511 (Docket DE 05-064), the Petition contains a Bid Evaluation Report ("Report") in which UES provides a detailed analysis of the solicitation process. See Exhibit RSF-1, Schedule RSF-1. In addition, UES has provided Schedule LSM-4 which contains the calculation of the G1 Default Service Power Supply charges and supply related working capital, respectively.

2. Tab A of the Report contains the following information and material: a brief narrative discussion of the comparison of the bids received; identification of the suppliers who responded to the Request for Proposals ("RFP") issued by UES on February 2, 2010; a pricing summary consisting of a comparison of all price bids, which is followed by each bidder's final pricing; a summary of each bidder's financial security requirements of UES and each bidder's own provision of financial security and creditworthiness, and which includes UES' ranking of bidders in terms of financial security, taking into account both the credit requirements imposed on UES and the

financial security offered by the bidder; information provided by each bidder upon their submission of the proposal submission form; the contact list used by UES during the RFP process, including a summary of UES' communications with each contact and UES' expectations with regard to each potential bidder's intention to bid; and the final Power Supply Agreement ("PSA") redlined against the original PSA as issued.

3. UES seeks protection from public disclosure of all of the information contained in Tab A because it is confidential commercial and financial information. The bidding suppliers' information, including each supplier's identity, bid price and non-price terms, and other information provided to UES in response to the RFP, has been provided to UES pursuant to express understandings that this material will be maintained as confidential. UES submits that suppliers will be reluctant to participate in future solicitations by UES, and may completely refuse to participate in this market, if their confidential bid information is publicly disclosed. Disclosure of this information may detrimentally impact upon such suppliers' ability to participate in competitive solicitations in other markets within the northeast region as well. For the same reasons, UES seeks protection from public disclosure of the confidential information provided to Commission Staff and the Office of Consumer Advocate by e-mail on March 17, 2010.

4. UES also requests confidential treatment for the "Total G1 Class DS Suppler Charges," "Working Capital Requirement," "Supply Related Working Capital," and "Provision for Uncollected Accounts," found on columns (a), (d), (f) and (l) of Page 3 and columns (a), (d), (f) and (g) of Page 5 of Schedule LSM-4. UES seeks confidential treatment of this information because if any of it is disclosed, the G1 class Wholesale Rate may be calculated. For example, since the kWh purchases are provided elsewhere, the Total G1

Class DS Supplier Charges must remain confidential, because dividing that number by the purchases would yield the confidential Wholesale Rate. Additionally, since there is a known relationship between the Supplier Charges, the Working Capital Requirement, and Working Capital Costs, it is necessary not only to protect the Working Capital Requirement and associated Working Capital Costs, but also another cost element such as the Provision for Uncollected Accounts. Since the G1 class has just one supplier with monthly pricing, without protection of the Provision for Uncollected Accounts, the Supplier Charges and Working Capital Costs of this supplier may be derived.

6. UES does not claim that the "Supplier Charges," "Provision for Uncollected Accounts," "Supply Related Working Capital" and "Working Capital Requirement" are confidential information. However, UES seeks to redact this information from the publicly available material for a limited period because revealing it would allow a person to compute information – the Wholesale Rate - which is confidential. As a result of the Settlement Agreement in Docket DE 05-064, UES' supply-related working capital costs are to be recovered through default service rates. Thus, the inclusion of the above items in the attached schedule is necessary in order to show the calculation of the default service rate.

7. It is UES' understanding that a wholesale supplier is obligated, pursuant to certain reporting requirements, to report to the Federal Energy Regulatory Commission ("FERC") the price and volume of its wholesale contractual sales during each quarter, and to identify the party to whom the sale has been made, within 30 days of the end of that quarter. See FERC Docket No. RM01-8-000, Order No. 2001, 99 FERC ¶ 61, 107, 18 CFR Parts 2 and 35, issued April 25, 2002. This information is then available to the

public electronically from FERC through its Electronic Quarterly Reports. Until such time as this pricing information is required by FERC to be made public in this manner, it is the expectation and intent of the winning supplier to keep this information confidential so as to avoid disclosing price information which may be leveraged against it in other contemporaneous negotiations. Thus, it is critical that the Wholesale Rate and the "Supplier Charges," "Provision for Uncollected Accounts," "Supply related Working Capital Costs" and Working Capital Requirement" described above be redacted only until the Wholesale rate becomes publicly available at FERC, so that a person would not be able to derive the precise Wholesale Rate under the contract. Accordingly, UES is seeking that this information be protected until September 1, 2010.

8. UES also requests confidential treatment for information contained in Schedule DC-2 which may lead to disclosure of the payment terms of the underlying supplier contracts. Accordingly, UES has redacted the "Payment Date," the "Lead Period" and the "Weighted Days" from each of page in this schedule. UES seeks to redact this information from the publicly available material because revealing it would allow a person to compute information concerning the payments terms of its supply contracts, which is confidential.

9. R.S.A. 91-A:5(IV) expressly exempts from the public disclosure requirements of the Right-to-Know law, R.S.A. 91-A, any records pertaining to "confidential, commercial or financial information." The Commission's rule on confidential treatment of public records, Puc 203.08, also recognizes that confidential, commercial or financial information may be appropriately protected from public disclosure pursuant to an order of the Commission.

10. UES' request for a protective order is not inconsistent with the public disclosure requirements of the Right-to-Know law, R.S.A. 91-A. This statute generally provides open access to public records, but the Commission has recognized that the determination whether to disclose confidential information involves a balancing of the public's interest in full disclosure with the countervailing commercial or private interests for non-disclosure. In this instance, the interests in support of a protective order of limited duration, in addition to those discussed above, include as well the interest of the State in promoting a competitive market for electricity, as expressed in RSA 374-F:1. The Commission has granted UES' request for confidential treatment of similar information contained in its previous DS tariff filings. UES submits that the considerations which the Commission determined supported approval of the protective order in those instances apply to the present filing. In Order No. 24,682, the Commission agreed that the information in "Provision for Uncollected Accounts" and "Supply-Related Working Capital" taken in combination would reveal the wholesale cost of power from the winning bidders and therefore constitutes confidential commercial or financial information protected from disclosure by RSA 91-A. In past DS proceedings, the Commission has also recognized the necessity of protecting information concerning the payment terms of the supply contracts from public disclosure.

WHEREFORE, UES respectfully requests that the Commission issue an order protecting the confidential information specified herein from public disclosure.

Respectfully submitted,

UNITIL ENERGY SYSTEMS, INC.
By its Attorney,

Gary Epler
Chief Regulatory Attorney
Unitil Service Corporation
65 Liberty Lane West
Hampton, NH 03842
Tel. (603) 773-6440

Dated: March 12, 2010

CERTIFICATE OF SERVICE

I certify that I have caused copies of Unitil Energy System's, Inc., "Petition For Approval of Default Service Solicitation and Proposed Default Service Tariff" to be served on the following parties or individuals:

Suzanne Amidon, Staff Counsel (by Hand-Delivery)
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301-2429

Meredith Hatfield, Consumer Advocate (by Hand-Delivery)
Office of Consumer Advocate
21 S. Fruit Street, Suite 18
Concord, NH 03301-2429

Dated at Hampton, New Hampshire this 12th day of March, 2010.

Gary Epler

Gary Epler

SUMMARY OF LOW-INCOME ELECTRIC ASSISTANCE PROGRAM DISCOUNTS

Low-Income Electric Assistance Program (LI-EAP) Discounts for Eligible Customers

Tier	Percentage of Federal Poverty Guidelines	Discount	Rate D Blocks	Rate D LI-EAP Discount(1)
1	176 - 185	5%	Customer Charge	($0.42)
			First 250 kWh	($0.00627)
			Excess 250 kWh	($0.00652)
2	151 - 175	7%	Customer Charge	($0.59)
			First 250 kWh	($0.00878)
			Excess 250 kWh	($0.00913)
3	126 - 150	18%	Customer Charge	($1.51)
			First 250 kWh	($0.02259)
			Excess 250 kWh	($0.02349)
4	101 - 125	33%	Customer Charge	($2.77)
			First 250 kWh	($0.04141)
			Excess 250 kWh	($0.04306)
5	76 - 100	48%	Customer Charge	($4.03)
			First 250 kWh	($0.06024)
			Excess 250 kWh	($0.06264)
6	0 - 75	70%	Customer Charge	($5.88)
			First 250 kWh	($0.08784)
			Excess 250 kWh	($0.09134)

(1) Total utility charges from Page 4 (excluding the Electricity Consumption Tax) plus Non-G1 class Fixed Default Service Rate multiplied by the appropriate discount.

Authorized by NHPUC Order No. in Case No. DE 10-028, dated

CALCULATION OF THE DEFAULT SERVICE CHARGE

	Non-G1 Class Default Service:	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Total**
	Power Supply Charge							
1	Reconciliation	($16,099)	($18,428)	($21,804)	($21,688)	($17,803)	($17,524)	($113,347)
2	Total Costs	$4,721,482	$5,530,518	$6,830,374	$6,988,403	$5,299,468	$5,285,776	$34,656,022
3	Reconciliation plus Total Costs (L.1 + L.2)	$4,705,383	$5,512,090	$6,808,569	$6,966,715	$5,281,665	$5,268,252	$34,542,674
4	kWh Purchases	63,001,518	72,116,000	85,328,322	84,873,727	69,670,112	68,579,121	443,568,800
5	Total, Before Losses (L.3 / L.4)	$0.07469	$0.07643	$0.07979	$0.08208	$0.07581	$0.07682	$0.07787
6	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
7	Total Retail Rate - Variable Power Supply Charge (L.5 * (1+L.6))	$0.07947	$0.08133	$0.08490	$0.08734	$0.08066	$0.08174	
8	Total Retail Rate - Fixed Power Supply Charge (L.5 * (1+L.6))							$0.08286
	Renewable Portfolio Standard (RPS) Charge							
9	Reconciliation	$1,551	$1,775	$2,101	$2,090	$1,715	$1,688	$10,921
10	Total Costs	$118,486	$135,627	$160,474	$159,619	$131,029	$128,975	$834,210
11	Reconciliation plus Total Costs (L.9 + L.10)	$120,037	$137,402	$162,575	$161,709	$132,744	$130,663	$845,131
12	kWh Purchases	63,001,518	72,116,000	85,328,322	84,873,727	69,670,112	68,579,121	443,568,800
13	Total, Before Losses (L.11 / L.12)	$0.00191	$0.00191	$0.00191	$0.00191	$0.00191	$0.00191	$0.00191
14	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
15	Total Retail Rate - Variable RPS Charge (L.13 * (1+L.14))	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	
16	Total Retail Rate - Fixed RPS Charge (L.13 * (1+L.14))							$0.00203
17	Total Retail Rate - Variable Default Service Charge (L.7 + L.15)	$0.08150	$0.08336	$0.08693	$0.08937	$0.08269	$0.08377	
18	Total Retail Rate - Fixed Default Service Charge (L.8+L.16)							$0.08489

CALCULATION OF THE DEFAULT SERVICE CHARGE

	G1 Class Default Service:	**May-10**	**Jun-10**	**Jul-10**	**Total**
	Power Supply Charge				
1	Reconciliation	($2,830)	($2,543)	($3,178)	($8,550)
2	Total Costs	$752,196	$652,785	$843,245	$2,248,225
3	Reconciliation plus Total Costs (L.1 + L.2)	$749,366	$650,242	$840,067	$2,239,675
4	kWh Purchases	11,344,763	10,194,853	12,739,542	34,279,157
5	Total, Before Losses (L.3 / L.4)	$0.06605	$0.06378	$0.06594	
6	Losses	4.591%	4.591%	4.591%	
7	Total Retail Rate - Variable Power Supply Charge (L.5 * (1+L.6))	$0.06909	$0.06671	$0.06897	
	Renewable Portfolio Standard (RPS) Charge				
8	Reconciliation	$4,315	$3,877	$4,845	$13,038
9	Total Costs	$21,720	$19,519	$24,391	$65,630
10	Reconciliation plus Total Costs (L.8 + L.9)	$26,035	$23,396	$29,236	$78,668
11	kWh Purchases	11,344,763	10,194,853	12,739,542	34,279,157
12	Total, Before Losses (L.10 / L.11)	$0.00229	$0.00229	$0.00229	
13	Losses	4.591%	4.591%	4.591%	
14	Total Retail Rate - Variable RPS Charge (L.12 * (1+L.13))	$0.00240	$0.00240	$0.00240	
15	Total Retail Rate - Variable Default Service Charge (L.7 + L.14)	$0.07149	$0.06911	$0.07137	

Authorized by NHPUC Order No.   in Case No. DE 10-028, dated

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

ROBERT S. FURINO

New Hampshire Public Utilities Commission

Docket No. DE 10-028

March 12, 2010

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LIST OF SCHEDULES

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert S. Furino. My business address is 6 Liberty Lane West, Hampton, NH.

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

A. I am employed by Unitil Service Corp. (the "Service Company") as Director of the Energy Contracts department. The Service Company provides professional services to Unitil Energy Systems, Inc. ("UES").

Q. Please briefly describe your educational and business experience.

A. I received my Bachelor of Arts Degree in Economics from the University of Maine in 1991. I joined the Service Company in March 1994 as an Associate DSM Analyst in the Regulatory Services Department and have worked in the Regulatory, Product Development, Finance and Energy Contracts departments. My primary responsibilities involve energy supply acquisition.

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

A. Yes. I have testified before the Commission on many occasions.

II. PURPOSE OF TESTIMONY

Q. Please describe the purpose of your testimony.

A. My testimony documents the solicitation process followed by UES in its acquisition of Default Service power supplies ("DS") for its G1 and Non-G1 customers as approved by the Commission in Order No. 24,511, granting UES' Petition for Approval of a Default Service Supply Proposal for G1 and Non-G1 Customers and Approval of Solicitation Process as amended by the Settlement Agreement filed with the Commission on August 11, 2005 (the "Order"). With the current RFP, UES has contracted for a 3-month DS power supply for its G1 customers and 25% of DS power supply for Non-G1 customers for two years with service beginning May 1, 2010.

I describe how UES solicited for bids from wholesale suppliers to provide the supply requirements in accordance with the terms of the Order as UES has done in prior DS supply solicitations. I also describe how the proposals received were evaluated and the winning bidders were chosen. Supporting documentation and additional detail of the solicitation process followed is provided in the Bid Evaluation Report ("Report"), attached as Schedule RSF-1. A copy of the RFP as issued is attached as Schedule RSF-2, and an updated Customer Migration Report is attached as Schedule RSF-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 12 month history which covers the period from November 2008 through October 2009.

Lastly, RPS Compliance Cost Estimates are included as Schedule RSF-4. My testimony reviews UES' approach to compliance with the Renewable Portfolio Standard (RPS) which went into effect in January 2008. Schedule RSF-4 details projected obligations and price assumptions for the coming rate period. The price assumptions listed in Schedule RSF-4 are based on purchase history and current market data.

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

A. UES requests that the Commission:

- Find that: UES has followed the solicitation process approved by the Commission; UES' analysis of the bids submitted was reasonable; and UES has supplied a reasonable rationale for its choice of the winning supplier. In addition, UES also seeks approval for a RECs purchase made outside of the RFP process, details of which are provided in Tab A.
- 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 seller under the supply agreement are approved for inclusion in retail rates.

- Issue an order granting the approvals requested in UES' Petition on or before March 19, 2010, 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 agreement for DS power supplies.

A. In the same manner as its prior solicitations for default service supplies, UES conducted an open solicitation in which it actively sought interest among potential suppliers and provided potential suppliers with access to sufficient information to enable them to assess the risks and obligations associated with providing the services sought. 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 February 2, 2010, which is attached as Schedule RSF-2, as well as summarized in the Report attached as Schedule RSF-1.

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

A. UES announced the RFP's availability electronically to all participants in NEPOOL by notifying all members of the NEPOOL Markets Committee via email. UES also announced the issuance of the RFP via email to a list of power suppliers and other entities such as distribution companies, consultants, brokers and members of public agencies who have previously expressed interest in receiving copies of UES's solicitations. UES followed up the email announcements with telephone calls to the power suppliers to solicit their interest. In addition, UES issued a media advisory to the power markets trade press Megawatt Daily on February 3, 2010 announcing the issuance of the RFP.

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

A. The RFP described the details of UES' DS, the related customer-switching rules, and the form of power service sought. 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; historical monthly retail sales and customer counts by rate class and supply type; a generic listing of large customers showing sales, peak demands, capacity tag values and supply type; and the evaluation loads, which are the estimated monthly volumes that UES would use to weight bids in terms of price. The hourly load data and capacity tags, retail sales report and large customer data were all updated prior to final bidding. All documents and data files were provided to potential suppliers via UES' corporate website (www.unitil.com/rfp).

Q. How did UES evaluate the bids received?

A. UES evaluated the bids on both quantitative and qualitative criteria, including price, 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 along with the RFP.

UES selected Hess Corporation ("Hess") as the supplier for the 3-month G1 supply requirement and TransCanada Power Marketing Ltd ("TCPM") as the supplier for 25% Non-G1 requirement for two years. UES believes that Hess and TCPM offered the best overall value in terms of both price and non-price considerations for the respective supply requirements sought.

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

A. Schedule RSF-1 contains the Report which further details the solicitation process, the evaluation of bids, and the selection of the winning bidder. The Report contains a narrative discussion of the solicitation process. A confidential section labeled "Tab A" follows the narrative. Tab A includes additional discussion regarding the selection of the winning bidders and presents several supporting exhibits that list the suppliers who participated, the pricing they submitted and other information considered by UES in evaluating final proposals, including the red-lined versions of the final supply agreements. UES seeks protective treatment of all materials in provided in Tab A.

On the basis of the information and analysis contained in the Report, UES submits that it has complied with the Commission's requirements set forth in the Order, and that the resulting DS 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 indicate the planned issuance date, filing date and expected approval date associated with UES' next default service solicitation.

A. UES' next default service solicitation will be for one hundred percent (100%) of G1 supplies for a three-month period, beginning August 1, 2010. UES plans to issue an RFP for these supplies on May 11, 2010, with a filing for approval of solicitation results planned for June 11, 2010 and approval anticipated on June 18, 2010.

III. RENEWABLE PORTFOLIO STANDARD COMPLIANCE

Q. Please review the method by which UES intends to comply with the Renewable Portfolio Standard ("RPS") requirements.

A. . For 2009 compliance, UES has completed the first of two RFPs for RECs under which it purchased approximately fifty percent of its 2009 REC obligations. UES issued its second REC RFP, which seeks the balance of its 2009 REC obligations, on March 4, 2010. UES plans to follow the same format for 2010 compliance by issuing the first RFP for 50% of its 2010 REC obligations on October 11, 2010. In addition, UES has also made one REC purchase toward its 2009 RPS requirements outside of the RFP process and seeks approval of this transaction in this filing.

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

A. The current solicitation is for default service power supply during 2010. To comply with RPS requirements for the months of 2010 associated with the supplies that have been procured as a result of the current RFP, UES will need to provide Class I RECs for 1.0 percent of sales; Class II RECs for 0.04 percent of sales; Class III RECs for 5.5 percent of sales; and Class IV RECs for 1.0 percent of sales. UES currently estimates the cost of Class I RECs at $29.00; Class II RECs at $55.00; Class III RECs at $27.00; and Class IV RECs at $26.00. These values were derived from broker sheets published by renewable energy brokers and from the bidding activity under UES' recent REC RFP, which was concluded in late November, with reference to changes in percentage obligations from 2009 to 2010 for each Class as well as expected alternative compliance prices.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

/

DE 10-028 – Unitil Energy Systems, Inc.

Default Service RFP
Bid Evaluation Report

Large Customers (100%): May 1, 2010– July 31, 2010
Small Customers (100%): May 1, 2010– April 30, 2012

RFP Issue Date: *February 2, 2010*

REDACTED VERSION

File Date: March 12, 2010

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

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Unitil Energy Systems, Inc.
Bid Evaluation Report

Introduction

On Tuesday February 2, 2010 UES announced that its Request for Proposals ("RFP") for Default Service ("DS") supplies for the period beginning May 1, 2010 was available. In accordance with UES' DS supply proposal as approved by the Commission in Order No. 24, 511 ("the Order"), UES issued this RFP to obtain fixed monthly price offers to supply default service customers; one-hundred percent (100%) of G1, or large customer group, for a three-month period and twenty five percent (25%) of non-G1 or small customers for a period of two years. Contract deliveries will begin May 1, 2010.

The RFP document issued on February 2, 2010, was consistent in form and substance to the prior RFP issued by UES on November 3, 2009. Shortly after issuance, UES filed with the Commission a redlined version of the current RFP, marked to show changes from the RFP issued on November 3, 2009. A copy of the RFP documents issued to the market on February 2, 2010, including the Proposal Submission Form, the proposed Power Supply Agreement ("PSA"), and the proposed PSA Amendment are attached to the petition as Schedule RSF-2.

UES received a positive response to this RFP, receiving bids from capable suppliers who competed to serve the load requirements. UES awarded the three month large customer default service requirement to Hess Corporation and the 24-month small customer service requirements to TransCanada Power Marketing Ltd. In UES' opinion, these suppliers offered the best overall value for the respective service requirements. 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' 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 attached as Tab A to this Report. Details of the market response, including bid prices, and certain non-price considerations and selection rationale, are included in the Tab A materials.

Solicitation Process

UES accomplished market notification of the RFP by announcing its availability electronically to all participants in NEPOOL, in particular, to the members of the NEPOOL Markets Committee on Tuesday February 2, 2010. UES also announced the issuance of the RFP to a list of contacts from energy companies who have previously expressed interest in receiving copies of UES's solicitations. During the process of soliciting interest in the RFP, the list was updated as appropriate. The list includes individuals representing 35 separate power suppliers who were provided with the announcement; this count does not include other distribution companies, consultants (unless working of behalf of a named client who might participate), brokers or members of public agencies. In addition, UES issued a media advisory to the power markets trade press announcing the issuance of the RFP.

The RFP documents and accompanying data files were provided to interested parties using Unitil Corporation's website (www.unitil.com/rfp), under "Current Procurement" for UES (please note, those documents can now be found under the "Concluded Procurements" section). The RFP described the particulars of UES' 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"), a proposed PSA Amendment for use by existing suppliers and various data files.

To gain the greatest level of market interest in supplying the loads, UES endeavored to provide potential bidders with appropriate and accessible information. Along with the

RFP, UES provided potential bidders with historical hourly loads and daily capacity tag values for UES' DS customers for the period from January 1, 2008 through December 31, 2009. UES also provided an Excel spreadsheet containing historic retail monthly sales and customers reports from May 2003 through December 2009. The monthly reports detail by customer rate class the monthly retail billed kWh sales and the number of customers receiving DS and competitive generation supply. The hourly loads and daily capacity file was updated prior to final bidding to provide data through February 2010, and the retail sales report was updated to provide data through January 2010.

The RFP instructed potential suppliers on how to access class average load shape (8760 hours) data located on Unitil Corporation's website and provided distribution loss factors associated with each rate class. Data on large customer characteristics and migration activity was also provided. The data included a generic listing of all G1 customers showing each customer's annual energy consumption, peak demand and ICAP tag for the capacity year starting June 1, 2009, each customer's current supply type (default service or competitive generation), date of last transaction and meter read billing cycle. Lastly, UES provided 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 weight 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 Tuesday, February 23, 2010, UES received several 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 Tuesday, March 9, 2010 UES received final pricing from several bidders and conducted its evaluation. UES selected and notified Hess Corporation and TransCanada Power Marketing Ltd as the winner of the service requirements. All other bidders were notified that they were not selected.

Selection of Winning Bidders

UES based its selection of winning bidders on both quantitative and qualitative criteria. When the indicative bids were received, 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. When final bids were received, UES compiled weighted average prices using the evaluation loads that were issued to bidders along with the RFP. UES then evaluated the price and non-price aspects of the final bids received. The comparison of bids contained in Tab A, which is confidential and which includes materials documenting UES's rationale for its selection of winning bidders, is attached.

Unitil Energy Systems, Inc. ("UES")

Default Service
Request for Proposals

UES Service Requirements

Large Customers (100%): May 1, 2010– July 31, 2010
Small Customers (100%): May 1, 2010– April 30, 2012

Issue Date: February 2, 2010

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's retail customers beginning on May 1, 2003.

On September 9, 2005, the NHPUC approved UES' plan for procurement of default service supply for the period beginning May 1, 2006[2]. UES procures the power supply required to meet its default service obligations for small customers through four full requirements contract blocks, each for an equal share (25%) of the service requirement. Two of these contracts are for one-year terms and two are for three-year terms. One of the one-year contracts begins on May 1 each year and the other begins on November 1 each year. One of the three-year contracts begins every third May 1 and the other begins every third November 1. UES procures the power supply required to meet its default service obligations for large customers through quarterly contracts for the full (100%) requirements. Each quarter, UES procures a replacement contract for its large customers.

Via this request for proposals ("RFP"), UES is seeking competing fixed monthly price offers to supply two default service contracts. One for 100% of large customer default service requirements, three months in duration, and one for 25% of small customers 24 months in duration. All contract deliveries will begin May 1, 2010.

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 supplier. This RFP and supporting materials can be obtained on Unitil's website at the following address: www.unitil.com/rfp, under "Current Procurement" for UES. The complete RFP text is available as a single ZIP file ("UES_DS_RFP_Package_2010-02.zip"). In addition, the RFP and its appendices, including the submission form, bid sheet and proposed contract, have been included as separate, editable electronic files. A number of electronic data files have also been included in Microsoft Excel format. The contents of each file are described in this document. Please contact Michael Lundgren at (603) 773-6549 or at lundgren@unitil.com with any questions regarding these materials.

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[1] See Docket DE 01-247.

[2] See Docket DE 05-064.

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 unique customer group and supply period combination sought will be evaluated and awarded separately.

Load Asset Description	Customer Rate Classes	Load Asset #
UES Small Default Load	D, G2, OL	11451, 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. 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 1, 2009 through January 31, 2010. 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_Hourly_Loads_Cap_Tags_2010-02.xls".

Historic Retail Monthly Sales Report

Monthly sales data from May 2003 through December 2009 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 "Retail_Sales_Report_2010-02.xls".

Class Average Load Shapes (8760 hours), as measured at the customer meter level, are available on Unitil's website at the following address:

http://services.unitil.com/content/xls/UESPROFILES.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	G2 (Regular General)	6.392%
Small Customers	OL (Outdoor Lighting)	6.468%
Small Customers	D (Domestic)	6.468%
Large Customer	G1 (Large General)	4.591%

Large Customer Activity is demonstrated by a generic listing of the annual retail energy consumption, peak demands and ICAP tags of UES's G1 customers. The tags reflect the capacity year which began June 1, 2009. This listing indicates each customer's current supply type (default service or competitive generation), date of last transaction, and billing cycle. Please see the file named "UES_Large_Customers_2010-02.xls."

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. The Evaluation Loads are included on the bid sheets. Please see the file named "Bid_Sheets_2010-02.xls."

III. General Provisions

Terms and Conditions

For those default service loads that respondents choose to bid, respondents must offer fixed monthly prices 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.

Along with this RFP, UES has provided a proposed contract ("Power Supply Agreement") which details the contractual terms and conditions under which default service as sought herein will be provided. Please see the file named "App_B_Power_Agreement_2010-02.doc". UES is generally willing to adopt or amend previously negotiated or executed agreements. Please see the file named "App_B1_PSA_Amend_2010-02.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.

Item	Date
Issue DS RFP	Tuesday 2/2/2010
Proposal Submission Forms Due (includes indicative pricing and contract comments)	Tuesday 2/23/2010
Final Pricing Due	Tuesday 3/09/2010 10:00AM
Winning Supplier Notified	3/9/2010– 1pm EPT
Contracts Executed	Wednesday, 3/10/2010

File for Approval of Rates	Friday, 3/12/2010
Anticipated Approval of Rates	Friday 3/19/2010
UES DS Service Commences	Friday, 5/1/2010

Respondents to this RFP must submit a completed Proposal Submission Form, including indicative pricing and any proposed contract modifications on or before February 23, 2010 and final pricing on March 9, 2010, as shown above. All submissions should be marked "UES DS RFP 2010-02" and sent via e-mail to energy_contracts@unitil.com. Please direct any questions to Michael Lundgren at (603) 773-6549. lundgren@unitil.com

Proposal Submission Forms are attached as Appendix A. Please see the file named "App_A_Submission_Form_2010-02.doc." Forms are due on **Tuesday, February 23, 2010**

Indicative Pricing is due along with the Proposal Submission Form. Indicative pricing should be submitted using the "Indicative Pricing" sheet from the Microsoft Excel file called "Bid_Sheets_2010-02.xls". Bidders will find that all cells highlighted in yellow are where inputs should be entered.

Contract Comments, on either the full Power Supply Agreement or on the Amendment, are also due along with the Proposal Submission Form. 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 Pricing" sheet from the Microsoft Excel file called "Bid_Sheets_2010-02.xls". Respondent's name must be clearly marked. Final pricing is due by **10:00 a.m. EPT on Tuesday, March 9, 2010.**

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 Tuesday, **March 9, 2010**. Other bidders will be notified they were not selected shortly thereafter.

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 Michael Lundgren at (603) 773-6549 or at lundgren@unitil.com.

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 Large Default Load	100%	May. 1, 2010	Jul. 31, 2010
UES Small Default Load	25%	May 1, 2010	Apr 30, 2012

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 10019 (Large Customer Group), 11451 and 11452 (Small Customer Group). The percentage Ownership Share for each load asset shall be as listed on the table above under Supply Obligation Period. 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

A minimum Electric Renewable Portfolio Standard (RPS) was established on May 11th 2007, implementing RPS requirements in New Hampshire beginning in January 2008. There are no requirements to provide renewable energy credits (RECs) for RPS compliance associated with the service sought herein.

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_Submission_Form_2010-

02.doc." Respondents are asked to complete the submission form and return it to Michael Lundgren 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 has included with this RFP a copy of its most recent financials. Please see the file named "UES_Financials_2010-02.zip." 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

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.

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; please see file named "Bid_Sheets_2010_02.xls," as described at the end of Section II.

Appendix A: Proposal Submission Form

Please see the file named "App_A_Submission_Form_2010-02.doc"

RESPONDENT:

APPENDIX A: PROPOSAL SUBMISSION FORM

RESPONDENT:

1. General Information

Name of Respondent	
Name of Parent or Guarantor (if any)	
Principal contact person - Name - Title - Company - Mailing address - Telephone number - Fax number - E-mail address	
Secondary contact person (if any) - Name - Title - Company - Mailing address - Telephone number - Fax number - E-mail address	
Legal status of Respondent (e.g., sole proprietorship, partnership, limited partnership, joint venture, or corporation)	
State of incorporation, residency or organization	
The names of all general and limited partners (if Respondent is a partnership)	

RESPONDENT:

Description of Respondent and all relevant affiliated entities and joint ventures	

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.		

RESPONDENT:

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. Please also identify the name, title and telephone number of the principal manager of the customer/client who asserted the event of default or noncompliance.	
Describe any facts presently known to Respondent that might adversely affect its ability to provide the service bid herein as provided for in the Request for Proposals.	

4. NEPOOL and Power Supply Experience

Is Respondent a member of NEPOOL?	
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.	

RESPONDENT:

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
Please provide any proposed modifications to the Power Supply Agreement 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.	

Appendix B: Proposed Power Supply Agreement (PSA)

Please see the file named "App_B1_PSA_Amendment_2010-02.doc"

POWER SUPPLY AGREEMENT

This POWER SUPPLY AGREEMENT ("Agreement") is dated as of March 10, 2010 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 February 2, 2010 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.

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 applicable 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 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. The Points of Interconnection between the Buyer and either Public Service Company of New Hampshire or various small power producers, listed in Appendix C. The Buyer may add or remove Points of Interconnection to its service territory.

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.

GAAP means General Accepted Accounting Principals 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 Manuals means the ISO Manual M-06 Financial Transmission Rights, the ISO Manual M-11 Market Operations, the ISO Manual M-20 Installed Capacity, the ISO Manual M-27 Tariff Accounting, the ISO Manual M-28 Market Rule 1 Accounting, the ISO Manual M-29 Billing, the ISO Manual M-35 Definitions and Abbreviations, the ISO Manual M-36 Forward Reserve, the ISO Manual M-LRP Load Response Program, as they may be amended, restated, or succeeded from time to time. In the event that ISO adopts additional manuals, then these shall also be included in this definition.

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 Gl.

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.

Moody's means Moody's Investors Service, its successors and assigns.

MWh means Megawatt-hour.

NE-GIS 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.

NE-GIS Certificates 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.

NEPOOL means the New England Power Pool, or its successor.

NEPOOL Agreement means the Second Restated New England Power Pool Agreement dated as 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.

NHPUC means the New Hampshire Public Utilities Commission.

NH Load Zone means the New Hampshire Reliability Region as defined in the ISO Rules.

PTF means facilities categorized as Pool Transmission Facilities under ISO Rules.

Requirements shall be defined in Section 4.2(c).

Retail Delivery Tariff means UES' Tariff for Electric Delivery in the State of New Hampshire.

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

Service Requirement 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.

Shareholder Equity means the Common Stock Equity as defined in the audited annual financial statements prepared in accordance with current U.S. GAAP. However, Shareholder Equity shall be exclusive of accumulated Other Comprehensive Income.

Small Customer Group means the retail customers assigned to the following customer rate classes: Domestic Delivery Service Schedule D, Regular General Service Schedule G2, and Outdoor Lighting Service Schedule OL.

ARTICLE 3. TERM, SERVICE PROVISIONS AND REGISTRATION REQUIREMENTS

Section 3.1 Term

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 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. Using the NE-GIS, then the Seller would be obligated to transfer the NE-GIS Certificates, associated with the Service Requirements into the Buyer's NE-GIS Account. The Buyer would be obligated to confirm such transfers in the NE-GIS.

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 March 19, 2010, 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, Reliability Must-Run Operating Reserves ("RMR") other than RMR Operating Reserve charges that are monthly fixed-cost charges paid to resources pursuant to agreements negotiated under Market Rule 1, Appendix A, Section 6, net commitment period compensation ("NCPC") other than RMR NCPC charges that are monthly fixed-cost charges paid to resources pursuant to agreements negotiated under Market Rule 1 Appendix A, Section 6, 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.

Section 5.2 Billing and Payment

(a) On or before the tenth (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 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

(a) 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. The Buyer will normally report to the ISO and to Seller Seller's estimated Delivered Energy by 1:00 P.M EPT of the second following Business Day. 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. 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 (i) with respect to Seller or Seller's credit support provider, [Seller's credit support provider], the Credit Rating of Seller or Seller's credit support provider is downgraded by Moody's and S&P, such that its Credit Rating is below an Investment Grade; or (ii) with respect to Buyer, its Shareholder Equity is at any time less than $25,000,000 (each 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 or Seller has and maintains an Investment Grade Credit Rating or at least the minimum Shareholder Equity 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 or its Shareholder Equity, 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 Forward Contract.

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. Robert S. Furino
Director, Energy Contracts
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. Mark H. Collin
Treasurer
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 superceded, 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: ______________________________

Its ______________________________

[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 February 2, 2010

Service Requirement	Load Asset Name and ID	Load Responsibility	Schedule 1	Schedule 2
100% UES Large Customer Group	UES Large Default Load, 10019	100%	May 1, 2010	Jul 31, 2010
25% UES Small Customer Group	UES Small Default Load, 11451, 11452	25%	May 1, 2010	Apr 30, 2012

APPENDIX B
Monthly Contract Rate by Service Requirement
Dollars per MWh

For service pursuant to Buyer's RFP issued on February 2, 2010

Service Requirement	May 2010	Jun 2010	Jul 2010
100% UES Large Customer Group (3 months)			

<table>
<tr><td>Service Requirement</td><td>May-10</td><td>Jun-10</td><td>Jul-10</td><td>Aug-10</td><td>Sep-10</td><td>Oct-10</td></tr>
<tr><td rowspan="7">25% UES
Small Customer Group
(24 months)</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Nov-10</td><td>Dec-10</td><td>Jan-11</td><td>Feb-11</td><td>Mar-11</td><td>Apr-11</td></tr>
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<tr><td>May-11</td><td>Jun-11</td><td>Jul-11</td><td>Aug-11</td><td>Sep-11</td><td>Oct-11</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Nov-11</td><td>Dec-11</td><td>Jan-12</td><td>Feb-12</td><td>Mar-12</td><td>Apr-12</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td></tr>
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APPENDIX C
POINTS OF INTERCONNECTION, REFERRED TO AS DELIVERY POINT

Points of Interconnection	Nominal Delivery Voltage	Metering Point	Nominal Metering Voltage
Garvins	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV
Concord Steam	3ϕ, 4 wire, 7.9/13.8 kV	At Connection Point	3ϕ, 4 wire, 7.9/13.8 kV
New Hampshire Hydro			
Lower Penacook Falls (1)	3ϕ, 4 wire, 19.9/34.5 kV	At Connection Point	3ϕ, 4 wire, 19.9/34.5 kV
Upper Penacook Falls (1)	3ϕ, 4 wire, 19.9/34.5 kV	At Connection Point	3ϕ, 4 wire, 19.9/34.5 kV
Briar Hydro (1)	3ϕ, 4 wire, 19.9/34.5 kV	At Connection Point	3ϕ, 4 wire, 19.9/34.5 kV
SES Concord Company L.P. (1)	3ϕ, 4 wire, 19.9/34.5 kV	At Connection Point	3ϕ, 4 wire, 19.9/34.5 kV
Hollis (Plains)	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV
Penacook	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV
Danville	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV
Guinea Road	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV
Kingston	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV
Timber Swamp	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV
Great Bay	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV

(1) Small power producer purchase delivery points.

Appendix B1: Proposed PSA Amendment

Please see the file named “App_B_Power_Agreement_2010-02.doc”

AMENDMENT No. [X]
OF
POWER SALES AGREEMENT

This Amendment No. [X] ("Amendment No. [X]"), dated and effective as of March10, 2010 (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 March 19, 2010, 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 February 2, 2010.

2. Appendix B is amended as attached hereto. The amendment adds pricing associated with the results of the RFP issued by Buyer on February 2, 2010.

3. Article 2 shall be modified to add the following definitions (*unless already incorporated into Agreement*):

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

Shareholder Equity means the Common Stock Equity as defined in the audited annual financial statements prepared in accordance with current U.S. GAAP. However, Shareholder Equity shall be exclusive of accumulated Other Comprehensive Income.

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:

Its_______________________________

[Company Name]

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 **February 2, 2010**

Service Requirement	Load Asset Name and ID	Load Responsibility	Schedule 1	Schedule 2
100% UES Large Customer Group	UES Large Default Load, 10019	100%	May 1, 2010	Jul 31, 2010
25% UES Small Customer Group	UES Small Default Load, 11451, 11452	25%	May 1, 2010	Apr 30, 2012

APPENDIX B
Monthly Contract Rate by Service Requirement
Dollars per MWh

For service pursuant to Buyer's RFP issued on **February 2, 2010**

Service Requirement	May 2010	Jun 2010	Jul 2010
100% UES Large Customer Group (3 months)			

Service Requirement	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
25% UES Small Customer Group (12 months)						
	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11
	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12

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
Feb-09	0	2,335,501	19,239,888	106,855	21,682,244
Mar-09	0	2,252,393	18,199,426	112,982	20,564,802
Apr-09	0	2,392,944	18,663,169	111,791	21,167,904
May-09	0	2,402,188	18,762,045	110,147	21,274,380
Jun-09	37,200	2,718,502	18,712,843	124,254	21,592,799
Jul-09	46,200	2,969,404	20,579,313	124,500	23,719,417
Aug-09	60,321	4,075,873	25,609,535	116,254	29,861,983
Sep-09	64,641	4,693,181	24,758,410	124,561	29,640,793
Oct-09	51,760	4,384,999	22,982,268	131,378	27,550,404
Nov-09	75,425	4,236,124	22,613,600	121,259	27,046,408
Dec-09	74,000	4,748,182	23,224,599	138,856	28,185,637
Jan-10	144,826	5,811,224	23,282,497	184,862	29,423,409

RETAIL SALES (kWh) by CUSTOMER CLASS
Total Sales

Month	DOMESTIC	REGULAR GENERAL	LARGE GENERAL	OUTDOOR LIGHTING	TOTAL
Feb-09	44,633,818	28,785,357	28,080,876	710,358	102,210,409
Mar-09	39,805,602	27,230,812	26,951,031	727,448	94,714,894
Apr-09	37,795,757	27,272,041	27,926,042	757,726	93,751,566
May-09	32,677,515	25,809,216	27,738,173	712,691	86,937,595
Jun-09	34,177,351	26,898,737	28,584,069	777,059	90,437,216
Jul-09	39,487,448	30,258,996	31,048,428	785,781	101,580,653
Aug-09	45,694,434	32,412,156	32,371,261	754,634	111,232,486
Sep-09	43,197,838	31,253,101	31,169,381	742,015	106,362,335
Oct-09	35,172,516	26,863,110	28,729,567	761,003	91,526,196
Nov-09	35,880,892	25,482,064	28,037,649	701,170	90,101,775
Dec-09	41,630,125	27,214,356	28,372,560	744,582	97,961,623
Jan-10	52,034,217	31,417,267	28,962,938	781,671	113,196,093

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

Month	DOMESTIC	REGULAR GENERAL	LARGE GENERAL	OUTDOOR LIGHTING	TOTAL
Feb-09	0.0%	8.1%	68.5%	15.0%	21.2%
Mar-09	0.0%	8.3%	67.5%	15.5%	21.7%
Apr-09	0.0%	8.8%	66.8%	14.8%	22.6%
May-09	0.0%	9.3%	67.6%	15.5%	24.5%
Jun-09	0.1%	10.1%	65.5%	16.0%	23.9%
Jul-09	0.1%	9.8%	66.3%	15.8%	23.4%
Aug-09	0.1%	12.6%	79.1%	15.4%	26.8%
Sep-09	0.1%	15.0%	79.4%	16.8%	27.9%
Oct-09	0.1%	16.3%	80.0%	17.3%	30.1%
Nov-09	0.2%	16.6%	80.7%	17.3%	30.0%
Dec-09	0.2%	17.4%	81.9%	18.6%	28.8%
Jan-10	0.3%	18.5%	80.4%	23.6%	26.0%

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
Feb-09	0	153	85	42	280
Mar-09	0	160	85	43	288
Apr-09	0	164	85	43	292
May-09	0	172	84	45	301
Jun-09	1	191	83	49	324
Jul-09	1	196	86	50	333
Aug-09	16	283	99	65	463
Sep-09	16	317	99	71	503
Oct-09	24	376	98	75	573
Nov-09	27	391	98	77	593
Dec-09	28	419	99	82	628
Jan-10	85	428	97	87	697

Total Customers

Month	DOMESTIC	REGULAR GENERAL	LARGE GENERAL	OUTDOOR LIGHTING	TOTAL
Feb-09	63,443	10,769	151	1,839	76,202
Mar-09	63,500	10,773	152	1,832	76,257
Apr-09	63,671	10,800	150	1,828	76,449
May-09	63,731	10,816	150	1,834	76,531
Jun-09	63,731	10,810	150	1,834	76,525
Jul-09	63,765	10,831	151	1,832	76,579
Aug-09	63,858	10,828	152	1,828	76,666
Sep-09	63,819	10,810	151	1,820	76,600
Oct-09	63,581	10,882	158	1,823	76,444
Nov-09	63,480	10,774	151	1,819	76,224
Dec-09	63,482	10,787	148	1,812	76,229
Jan-10	63,280	10,789	149	1,814	76,032

CUSTOMER COUNT by CLASS
Percentage of Customers Served by Competitive Generation

Month	DOMESTIC	REGULAR GENERAL	LARGE GENERAL	OUTDOOR LIGHTING	TOTAL
Feb-09	0.0%	1.4%	56.3%	2.3%	0.4%
Mar-09	0.0%	1.5%	55.9%	2.3%	0.4%
Apr-09	0.0%	1.5%	56.7%	2.4%	0.4%
May-09	0.0%	1.6%	56.0%	2.5%	0.4%
Jun-09	0.0%	1.8%	55.3%	2.7%	0.4%
Jul-09	0.0%	1.8%	57.0%	2.7%	0.4%
Aug-09	0.0%	2.6%	65.1%	3.6%	0.6%
Sep-09	0.0%	2.9%	65.6%	3.9%	0.7%
Oct-09	0.0%	3.5%	62.0%	4.1%	0.7%
Nov-09	0.0%	3.6%	64.9%	4.2%	0.8%
Dec-09	0.0%	3.9%	66.9%	4.5%	0.8%
Jan-10	0.1%	4.0%	65.1%	4.8%	0.9%

UES Default Service RFP Issued February 2, 2010
For Loads to be Served beginning May 1, 2010
RPS Compliance Cost Estimates

RPS Obligation

Year	Month	Class I	Class II	Class III	Class IV
2009	Nov-09	0.5%	0.00%	4.5%	1.0%
2009	Dec-09	0.5%	0.00%	4.5%	1.0%
2010	Jan-10	1.0%	0.04%	5.5%	1.0%
2010	Feb-10	1.0%	0.04%	5.5%	1.0%
2010	Mar-10	1.0%	0.04%	5.5%	1.0%
2010	Apr-10	1.0%	0.04%	5.5%	1.0%
2010	May-10	1.0%	0.04%	5.5%	1.0%
2010	Jun-10	1.0%	0.04%	5.5%	1.0%
2010	Jul-10	1.0%	0.04%	5.5%	1.0%
2010	Aug-10	1.0%	0.04%	5.5%	1.0%
2010	Sep-10	1.0%	0.04%	5.5%	1.0%
2010	Oct-10	1.0%	0.04%	5.5%	1.0%

Price Assumptions

Class I	Class II	Class III	Class IV
$ 50.00		$ 26.00	$ 27.00
$ 50.00		$ 26.00	$ 27.00
$ 55.00	$ 80.00	$ 25.00	$ 25.00
$ 40.00	$ 80.00	$ 27.00	$ 25.00
$ 40.00	$ 80.00	$ 27.00	$ 25.00
$ 40.00	$ 80.00	$ 27.00	$ 25.00
$ 29.00	$ 55.00	$ 27.00	$ 26.00
$ 29.00	$ 55.00	$ 27.00	$ 26.00
$ 29.00	$ 55.00	$ 27.00	$ 26.00
$ 29.00	$ 55.00	$ 27.00	$ 26.00
$ 29.00	$ 55.00	$ 27.00	$ 26.00
$ 29.00	$ 55.00	$ 27.00	$ 26.00

Customer Costs

Non G1 Retail Sales (MWH)	Class I	Class II	Class III	Class IV	Non G1 RPS Cost	Non G1 Cost $/MWH
57,631	$ 14,408	$ -	$ 67,429	$ 15,560	$ 97,397	$ 1.69
64,628	$ 16,157	$ -	$ 75,615	$ 17,450	$ 109,221	$ 1.69
77,321	$ 42,526	$ 2,474	$106,316	$ 19,330	$ 170,647	$ 2.21
67,952	$ 27,181	$ 2,174	$100,909	$ 16,988	$ 147,252	$ 2.17
66,466	$ 26,586	$ 2,127	$ 98,702	$ 16,616	$ 144,031	$ 2.17
58,654	$ 23,462	$ 1,877	$ 87,101	$ 14,663	$ 127,103	$ 2.17
59,192	$ 17,166	$ 1,302	$ 87,899	$ 15,390	$ 121,757	$ 2.06
67,754	$ 19,649	$ 1,491	$100,615	$ 17,616	$ 139,370	$ 2.06
80,167	$ 23,248	$ 1,764	$119,048	$ 20,843	$ 164,904	$ 2.06
79,740	$ 23,125	$ 1,754	$118,414	$ 20,732	$ 164,025	$ 2.06
65,457	$ 18,983	$ 1,440	$ 97,204	$ 17,019	$ 134,645	$ 2.06
64,431	$ 18,685	$ 1,417	$ 95,680	$ 16,752	$ 132,535	$ 2.06

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RPS Obligation

Year	Month	Class I	Class II	Class III	Class IV
2009	Nov-09	0.5%	0.00%	4.5%	1.0%
2009	Dec-09	0.5%	0.00%	4.5%	1.0%
2010	Jan-10	1.0%	0.04%	5.5%	1.0%
2010	Feb-10	1.0%	0.04%	5.5%	1.0%
2010	Mar-10	1.0%	0.04%	5.5%	1.0%
2010	Apr-10	1.0%	0.04%	5.5%	1.0%
2010	May-10	1.0%	0.04%	5.5%	1.0%
2010	Jun-10	1.0%	0.04%	5.5%	1.0%
2010	Jul-10	1.0%	0.04%	5.5%	1.0%
2010	Aug-10	1.0%	0.04%	5.5%	1.0%
2010	Sep-10	1.0%	0.04%	5.5%	1.0%
2010	Oct-10	1.0%	0.04%	5.5%	1.0%

Price Assumptions

Class I	Class II	Class III	Class IV
$ 50.00		$ 26.00	$ 27.00
$ 50.00		$ 26.00	$ 27.00
$ 55.00	$ 80.00	$ 25.00	$ 25.00
$ 40.00	$ 80.00	$ 27.00	$ 25.00
$ 40.00	$ 80.00	$ 27.00	$ 25.00
$ 40.00	$ 80.00	$ 27.00	$ 25.00
$ 29.00	$ 55.00	$ 27.00	$ 26.00
$ 29.00	$ 55.00	$ 27.00	$ 26.00
$ 29.00	$ 55.00	$ 27.00	$ 26.00
$ 29.00	$ 55.00	$ 27.00	$ 26.00
$ 29.00	$ 55.00	$ 27.00	$ 26.00
$ 29.00	$ 55.00	$ 27.00	$ 26.00

Customer Costs

G1 Retail Sales (MWH)	Class I	Class II	Class III	Class IV	RPS Cost	Cost $/MWH
5,424	$ 1,356	$ -	$ 6,346	$ 1,464	$ 9,167	$ 1.69
5,148	$ 1,287	$ -	$ 6,023	$ 1,390	$ 8,700	$ 1.69
10,095	$ 5,552	$ 323	$ 13,881	$ 2,524	$ 22,280	$ 2.21
9,505	$ 3,802	$ 304	$ 14,115	$ 2,376	$ 20,597	$ 2.17
9,593	$ 3,837	$ 307	$ 14,246	$ 2,398	$ 20,788	$ 2.17
9,606	$ 3,842	$ 307	$ 14,265	$ 2,402	$ 20,817	$ 2.17
10,847	$ 3,146	$ 239	$ 16,107	$ 2,820	$ 22,312	$ 2.06
9,747	$ 2,827	$ 214	$ 14,475	$ 2,534	$ 20,050	$ 2.06
12,180	$ 3,532	$ 268	$ 18,088	$ 3,167	$ 25,055	$ 2.06
11,283	$ 3,272	$ 248	$ 16,756	$ 2,934	$ 23,210	$ 2.06
10,876	$ 3,154	$ 239	$ 16,151	$ 2,828	$ 22,373	$ 2.06
10,438	$ 3,027	$ 230	$ 15,501	$ 2,714	$ 21,472	$ 2.06

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

LINDA S. MCNAMARA

New Hampshire Public Utilities Commission

Docket No. DE 10-028

March 12, 2010

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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 I at 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. In 1994 I graduated *cum laude* from the University of New Hampshire with a Bachelor of Science Degree in Mathematics. Since joining USC in June 1994, 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' Default Service Charge ("DSC") effective May 1, 2010, as reflected in the redline tariffs provided as Schedule LSM-1.

My testimony will focus on the reconciliation and rate development for the DSC. UES witness Robert S. Furino is sponsoring testimony which addresses the costs associated with these changes.

III. RETAIL RATE CALCULATIONS

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

A. As shown on Schedule LSM-1, Page 1, the proposed Non-G1 Fixed DSC is $0.08489 per kWh for the Non-G1 Class for the period May 1, 2010 through October 31, 2010. The proposed Non-G1 Variable DSC for this same period are also shown on this page. The proposed Non-G1 class Fixed DSC has also been incorporated into the Summary of Low-Income Electric Assistance Program Discounts, shown on Page 3 of Schedule LSM-1.

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 is the proposed Power Supply Charge and RPS Charge?

A. For the period May 1, 2010 through October 31, 2010, the proposed Non-G1 Fixed Power Supply Charge is $0.08286 per kWh and the proposed Non-G1 Fixed RPS Charge is $0.00203. Both of these figures, as well as the variable amounts for the same period, are shown on Schedule LSM-1, Page 1.

Q. How does this rate compare to the current rate?

A. The Non-G1 Fixed DSC of $0.08489 per kWh is a decrease of $0.00548 per kWh from the current DSC of $0.09037 per kWh. This decrease reflects lower contract costs for the period May 1, 2010 through October 31, 2010 compared to the contract costs for the current period November 1, 2009 through April 30, 2010.

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 the same manner.

The Variable Charge is calculated by dividing the total costs for the month, including a partial reconciliation of costs and revenues through January 31, 2010, by the estimated monthly Non-G1 kWh purchases. An estimated loss factor of 6.4% is then added to arrive at the proposed retail Variable Charges. The Fixed

Charge is calculated in a similar manner, except that the calculation is based on totals for the entire six month period.

In order to determine the reconciliation amounts included in both the Non-G1 class power supply and Non-G1 class RPS, the reconciliation balance as of January 31, 2010 was adjusted to account for RPS. The Non-G1 class power supply reconcilation balance also includes an adjustment to recognize that the current power supply charges, in effect through April 30, 2010, include a credit for the overcollection as of January 31, 2009. The current Non-G1 class RPS charges include no over- or undercollection.

Since UES reconciles its costs on an annual basis, only a portion of the total balance is reflected in the rate. UES apportioned the Power Supply balance and the RPS balance based on kWh over the twelve month period May 2010 through April 2011. This calculation is provided on Page 1 of Schedule LSM-2 for Power Supply and Page 1 of Schedule LSM-3 for RPS.

Q. Please explain the adjustment related to accounting for RPS.

A. This adjustment recognizes that UES has included RPS costs in its rates since January 1, 2009. However, these costs have not yet been paid but are being accrued. In order to prevent refunding these amounts, UES has added the amounts it has already collected in rates to the reconciliation balance. This method ensures that customers are appropriately compensated through the interest calculation, which reflects that these costs have not yet been paid.

Q. If UES recovers its RPS costs through its RPS charge, why does the Power Supply mechanism include an adjustment for RPS?

A. For the period January through July 2009, UES had one Non-G1 class default service reconciliation model. Effective August 1, 2009, a separate RPS rate and reconciliation mechanism was developed. Default service revenue collected for the period January through July 2009, however, included the recovery of costs associated with RPS, and this revenue remained in the default service model which became, on August 1, the Power Supply mechansim. In order to match actual 2009 RPS expense, all of which is included in the RPS mechanism, with 2009 RPS revenue, UES intends to move $914,358 out of the Power Supply mechanism and into the RPS mechansim[1].

Q. Have you provided details on the reconciliation?

A. Support for the January 31, 2010 Non-G1 class power supply reconciliation balance is provided on Schedule LSM-2, Page 2. Support for the January 31, 2010 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

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[1] UES plans to make this adjustment with its March 2010 accounting close.

the figures for collecton beginning May 1, 2010. Details for costs for the period February 2009 through January 2010 are provided on Page 3 of Schedule LSM-2 and 3. Page 4 of Schedule LSM-2 and 3 provide detail of revenue.

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

A. The details of forecasted costs for the period May through October 2010 are provided on Schedule LSM-2, Page 5. Line items for the various costs included in default service are shown and include: Total Non-G1 Class DS Supplier Charges, GIS Support Payments, Supply Related Working Capital, Provision for Uncollected Accounts, Internal Company Administrative Costs, Legal Charges, and Consulting Outside Service Charges.

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 May through October 2010 are provided on Schedule LSM-3, 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 Non-G1 Class DS Supplier Charges plus GIS

Support Payments, as shown on Schedule LSM-2, Page 5. It is calculated by multiplying the product of Total Non-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) by the prime rate.

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

The calculation of working capital included in the Power Supply Charge and the RPS Charge both rely on the results of the 2009 Default Service and Renewable Energy Credits Lead Lag Study, presented by Mr. Chong. The Non-G1 class Power Supply Charge working capital calculation uses 15.90 days and the Non-G1 class RPS Charge working capital calculation uses (301.67) days.

Q. What is the proposed G1 Class DSC?

A. Schedule LSM-1, Page 2, shows the proposed G1 Variable DSC of $0.07149 per kWh in May 2010, $0.06911 per kWh in June 2010, and $0.07137 per kWh in July 2010. There is no fixed option DSC for the G1 class.

The proposed DSC are comprised of two componets, as shown on Schedule LSM-1, Page 2: A Power Supply Charge and a Renewable Portfolio Standard ("RPS") Charge.

Q. What is the proposed Power Supply Charge and RPS Charge?

A. Schedule LSM-1, Page 2, shows the proposed G1 Variable Power Supply Charges of $0.06909 per kWh in May 2010, $0.06671 per kWh in June 2010, and $0.06897 per kWh in July 2010.

Also shown on Schedule LSM-1, Page 2, is the proposed G1 Variable RPS Charge of $0.00240 per kWh in May, June and July 2010.

Q. How do the G1 DSC compare to the current rate?

A. The current DSC, based on a simple three-month average, is $0.08812 per kWh. The proposed rate, based on a simple three-month average, is $0.07066 per kWh. This is a decrease of $0.01746 per kWh, on average, from the current rate. The decrease reflects current market prices.

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

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

The Variable Charge is calculated by dividing the costs for each month, including a partial reconciliation of costs and revenues through January 31, 2010, 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 Variable Charges.

Similar to the Non-G1 power supply and RPS balances, the G1 class power supply and RPS reconciliation balances as of January 31, 2010 were adjusted in order to determine the reconcilation amount for this filing. These adjustments are also provided on Page 1 of Schedule LSM-4 and 5. Also similar to the Non-G1 class, UES intends to move $100,577 of RPS cost recovery out of power supply and into RPS.

Q. Have you provided details on the reconciliation?

A. Support for the January 31, 2010 G1 class power supply reconciliation balance is provided on Schedule LSM-4, Page 2. Support for the January 31, 2010 G1 class RPS reconciliation balance is provided on Schedule LSM-5, Page 2. As described above, those figures have been adjusted in order to arrive at the figures for collecton beginning May 1, 2010. Details for costs for the period February 2009 through January 2010 are provided on Page 3 of Schedule LSM-4 and 5. Page 4 of Schedule LSM-4 and 5 provide detail of revenue.

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 May through July 2010 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, and Consulting Outside Service Charges.

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 May through July 2010 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, as shown on Schedule LSM-4, Page 5. It is calculated by multiplying 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) by the prime rate.

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

The calculation of working capital included in the Power Supply Charge and the RPS Charge both rely on the results of the 2009 Default Service and Renewable Energy Credits Lead Lag Study. The G1 class Power Supply Charge working capital calculation uses 13.72 days and the G1 class RPS Charge working capital calculation uses (297.66) days.

IV. BILL IMPACTS

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

A. Typical bill impacts as a result of changes to the DSC have been provided in Schedule LSM-6.

Pages 1 through 3 provide a table comparing the existing rates to the proposed rates for all the 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 4 shows bill impacts to the residential class based on the mean and median use. Page 4 is provided in a format similar to Pages 1 through 3.

Page 5 provides the overall average class bill impacts as a result of changes to the DSC. As shown, for customers on Default Service, the residential class will decrease about 3.7%, general service will decrease about 3.8%, large general service will decrease about 13.8% and outdoor lighting will decrease about 2.2%.

Pages 6 through 11 of Schedule LSM-6 provide typical bill impacts for all classes for a range of usage levels.

V. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.

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

CALCULATION OF THE DEFAULT SERVICE CHARGE

	Non-G1 Class Default Service:	~~Nov-09~~	~~Dec-09~~	~~Jan-10~~	~~Feb-10~~	~~Mar-10~~	~~Apr-10~~	~~Total~~
	Power Supply Charge							
1	Reconciliation	~~($1,343)~~	~~($1,367)~~	~~($1,495)~~	~~($1,675)~~	~~($1,515)~~	~~($1,459)~~	~~($8,854)~~
2	Total Costs	~~$4,970,497~~	~~$5,613,968~~	~~$6,876,334~~	~~$7,757,399~~	~~$6,210,110~~	~~$5,681,788~~	~~$37,110,097~~
3	Reconciliation plus Total Costs (L.1 + L.2)	~~$4,969,155~~	~~$5,612,601~~	~~$6,874,839~~	~~$7,755,724~~	~~$6,208,595~~	~~$5,680,329~~	~~$37,101,243~~
4	kWh Purchases	~~67,835,413~~	~~69,054,301~~	~~75,546,749~~	~~84,640,826~~	~~76,545,061~~	~~73,686,246~~	~~447,308,596~~
5	Total, Before Losses (L.3 / L.4)	~~$0.07325~~	~~$0.08128~~	~~$0.09100~~	~~$0.09163~~	~~$0.08111~~	~~$0.07709~~	~~$0.08294~~
6	Losses	~~6.40%~~	~~6.40%~~	~~6.40%~~	~~6.40%~~	~~6.40%~~	~~6.40%~~	~~6.40%~~
7	Total Retail Rate - Variable Power Supply Charge (L.5 * (1+L.6))	~~$0.07794~~	~~$0.08648~~	~~$0.09683~~	~~$0.09750~~	~~$0.08630~~	~~$0.08202~~	
8	Total Retail Rate - Fixed Power Supply Charge (L.5 * (1+L.6))							~~$0.08825~~
	Renewable Portfolio Standard (RPS) Charge							
9	Reconciliation	~~$0~~	~~$0~~	~~$0~~	~~$0~~	~~$0~~	~~$0~~	~~$0~~
10	Total Costs	~~$111,456~~	~~$113,458~~	~~$162,098~~	~~$181,610~~	~~$164,240~~	~~$158,106~~	~~$890,967~~
11	Reconciliation plus Total Costs (L.9 + L.10)	~~$111,456~~	~~$113,458~~	~~$162,098~~	~~$181,610~~	~~$164,240~~	~~$158,106~~	~~$890,967~~
12	kWh Purchases	~~67,835,413~~	~~69,054,301~~	~~75,546,749~~	~~84,640,826~~	~~76,545,061~~	~~73,686,246~~	~~447,308,596~~
13	Total, Before Losses (L.11 / L.12)	~~$0.00164~~	~~$0.00164~~	~~$0.00215~~	~~$0.00215~~	~~$0.00215~~	~~$0.00215~~	~~$0.00199~~
14	Losses	~~6.40%~~	~~6.40%~~	~~6.40%~~	~~6.40%~~	~~6.40%~~	~~6.40%~~	~~6.40%~~
15	Total Retail Rate - Variable RPS Charge (L.13 * (1+L.14))	~~$0.00175~~	~~$0.00175~~	~~$0.00228~~	~~$0.00228~~	~~$0.00228~~	~~$0.00228~~	
16	Total Retail Rate - Fixed RPS Charge (L.13 * (1+L.14))							~~$0.00212~~
17	Total Retail Rate - Variable Default Service Charge (L.7 + L.15)	~~$0.07969~~	~~$0.08823~~	~~$0.09911~~	~~$0.09978~~	~~$0.08858~~	~~$0.08430~~	
18	Total Retail Rate - Fixed Default Service Charge (L.8+L.16)							~~$0.09037~~

As shown on Schedule LSM-2, Page 1

	Non-G1 Class Default Service:	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
	Power Supply Charge							
1	Reconciliation	($16,099)	($18,428)	($21,804)	($21,688)	($17,803)	($17,524)	($113,347)
2	Total Costs	$4,721,482	$5,530,518	$6,830,374	$6,988,403	$5,299,468	$5,285,776	$34,656,022
3	Reconciliation plus Total Costs (L.1 + L.2)	$4,705,383	$5,512,090	$6,808,569	$6,966,715	$5,281,665	$5,268,252	$34,542,674
4	kWh Purchases	63,001,518	72,116,000	85,328,322	84,873,727	69,670,112	68,579,121	443,568,800
5	Total, Before Losses (L.3 / L.4)	$0.07469	$0.07643	$0.07979	$0.08208	$0.07581	$0.07682	$0.07787
6	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
7	Total Retail Rate - Variable Power Supply Charge (L.5 * (1+L.6))	$0.07947	$0.08133	$0.08490	$0.08734	$0.08066	$0.08174	
8	Total Retail Rate - Fixed Power Supply Charge (L.5 * (1+L.6))							$0.08286
	Renewable Portfolio Standard (RPS) Charge	As shown on Schedule LSM-3, Page 1						
9	Reconciliation	$1,551	$1,775	$2,101	$2,090	$1,715	$1,688	$10,921
10	Total Costs	$118,486	$135,627	$160,474	$159,619	$131,029	$128,975	$834,210
11	Reconciliation plus Total Costs (L.9 + L.10)	$120,037	$137,402	$162,575	$161,709	$132,744	$130,663	$845,131
12	kWh Purchases	63,001,518	72,116,000	85,328,322	84,873,727	69,670,112	68,579,121	443,568,800
13	Total, Before Losses (L.11 / L.12)	$0.00191	$0.00191	$0.00191	$0.00191	$0.00191	$0.00191	$0.00191
14	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
15	Total Retail Rate - Variable RPS Charge (L.13 * (1+L.14))	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	
16	Total Retail Rate - Fixed RPS Charge (L.13 * (1+L.14))							$0.00203
17	Total Retail Rate - Variable Default Service Charge (L.7 + L.15)	$0.08150	$0.08336	$0.08693	$0.08937	$0.08269	$0.08377	
18	Total Retail Rate - Fixed Default Service Charge (L.8+L.16)							$0.08489

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CALCULATION OF THE DEFAULT SERVICE CHARGE

	G1 Class Default Service:	~~Feb-10~~	~~Mar-10~~	~~Apr-10~~	~~Total~~	May-10	Jun-10	Jul-10	Total
						As shown on Schedule LSM-4, Page 1			
	Power Supply Charge								
1	Reconciliation	~~$34,513~~	~~$34,833~~	~~$34,881~~	~~$104,227~~	($2,830)	($2,543)	($3,178)	($8,550)
2	Total Costs	~~$849,132~~	~~$764,212~~	~~$747,891~~	~~$2,361,235~~	$752,196	$652,785	$843,245	$2,248,225
3	Reconciliation plus Total Costs (L.1 + L.2)	~~$883,645~~	~~$799,044~~	~~$782,772~~	~~$2,465,462~~	$749,366	$650,242	$840,067	$2,239,675
4	kWh Purchases	~~9,941,440~~	~~10,033,425~~	~~10,047,273~~	~~30,022,138~~	11,344,763	10,194,853	12,739,542	34,279,157
5	Total, Before Losses (L.3 / L.4)	~~$0.08889~~	~~$0.07964~~	~~$0.07791~~		$0.06605	$0.06378	$0.06594	
6	Losses	~~4.591%~~	~~4.591%~~	~~4.591%~~		4.591%	4.591%	4.591%	
7	Total Retail Rate - Variable Power Supply Charge (L.5 * (1+L.6))	~~$0.09297~~	~~$0.08329~~	~~$0.08149~~		$0.06909	$0.06671	$0.06897	
	Renewable Portfolio Standard (RPS) Charge					As shown on Schedule LSM-5, Page 1			
8	Reconciliation	~~$0~~	~~$0~~	~~$0~~	~~$0~~	$4,315	$3,877	$4,845	$13,038
9	Total Costs	~~$20,925~~	~~$21,118~~	~~$21,147~~	~~$63,190~~	$21,720	$19,519	$24,391	$65,630
10	Reconciliation plus Total Costs (L.8 + L.9)	~~$20,925~~	~~$21,118~~	~~$21,147~~	~~$63,190~~	$26,035	$23,396	$29,236	$78,668
11	kWh Purchases	~~9,941,440~~	~~10,033,425~~	~~10,047,273~~	~~30,022,138~~	11,344,763	10,194,853	12,739,542	34,279,157
12	Total, Before Losses (L.10 / L.11)	~~$0.00210~~	~~$0.00210~~	~~$0.00210~~		$0.00229	$0.00229	$0.00229	
13	Losses	~~4.591%~~	~~4.591%~~	~~4.591%~~		4.591%	4.591%	4.591%	
14	Total Retail Rate - Variable RPS Charge (L.12 * (1+L.13))	~~$0.00220~~	~~$0.00220~~	~~$0.00220~~		$0.00240	$0.00240	$0.00240	
15	Total Retail Rate - Variable Default Service Charge (L.7 + L.14)	~~$0.09517~~	~~$0.08549~~	~~$0.08369~~		$0.07149	$0.06911	$0.07137	

Authorized by NHPUC Order No. ~~25,054~~ in Case No. DE 10-028 ~~DE 09-009~~, dated ~~December 18, 2009~~

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

Eleventh~~Tenth~~ Revised Page 6
Superseding Tenth~~Ninth~~ Revised Page 6

SUMMARY OF LOW-INCOME ELECTRIC ASSISTANCE PROGRAM DISCOUNTS

Low-Income Electric Assistance Program (LI-EAP) Discounts for Eligible Customers

			Rate D		
Tier	Percentage of Federal Poverty Guidelines	Discount	Blocks	~~LI-EAP Discount(1)~~	LI-EAP Discount(1)
1	176 - 185	5%	Customer Charge	~~($0.42)~~	($0.42)
			First 250 kWh	~~($0.00655)~~	($0.00627)
			Excess 250 kWh	~~($0.00680)~~	($0.00652)
2	151 - 175	7%	Customer Charge	~~($0.59)~~	($0.59)
			First 250 kWh	~~($0.00917)~~	($0.00878)
			Excess 250 kWh	~~($0.00952)~~	($0.00913)
3	126 - 150	18%	Customer Charge	~~($1.51)~~	($1.51)
			First 250 kWh	~~($0.02357)~~	($0.02259)
			Excess 250 kWh	~~($0.02447)~~	($0.02349)
4	101 - 125	33%	Customer Charge	~~($2.77)~~	($2.77)
			First 250 kWh	~~($0.04322)~~	($0.04141)
			Excess 250 kWh	~~($0.04487)~~	($0.04306)
5	76 - 100	48%	Customer Charge	~~($4.03)~~	($4.03)
			First 250 kWh	~~($0.06287)~~	($0.06024)
			Excess 250 kWh	~~($0.06527)~~	($0.06264)
6	0 - 75	70%	Customer Charge	~~($5.88)~~	($5.88)
			First 250 kWh	~~($0.09168)~~	($0.08784)
			Excess 250 kWh	~~($0.09518)~~	($0.09134)

(1) Total utility charges from Page 4 (excluding the Electricity Consumption Tax) plus
Non-G1 class Fixed Default Service Rate multiplied by the appropriate discount.

Authorized by NHPUC Order No. ~~25,011~~ in Case No. DE 10-028 ~~DE 09-009~~, dated ~~September 4, 2009~~

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

		May-10 Estimated	Jun-10 Estimated	Jul-10 Estimated	Aug-10 Estimated	Sep-10 Estimated	Oct-10 Estimated	Total
1	Reconciliation (1)	($16,099)	($18,428)	($21,804)	($21,688)	($17,803)	($17,524)	($113,347)
2	Total Costs (Page 2)	$4,721,482	$5,530,518	$6,830,374	$6,988,403	$5,299,468	$5,285,776	$34,656,022
3	Reconciliation plus Total Costs (L.1 + L.2)	$4,705,383	$5,512,090	$6,808,569	$6,966,715	$5,281,665	$5,268,252	$34,542,674
4	kWh Purchases	63,001,518	72,116,000	85,328,322	84,873,727	69,670,112	68,579,121	443,568,800
5	Total, Before Losses (L.3 / L.4)	$0.07469	$0.07643	$0.07979	$0.08208	$0.07581	$0.07682	$0.07787
6	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
7	Total Retail Rate - Variable Power Supply Charge (L.5 * (1+L.6))	$0.07947	$0.08133	$0.08490	$0.08734	$0.08066	$0.08174	
8	Total Retail Rate - Fixed Power Supply Charge (L.5 * (1+L.6))							$0.08286

(1) Balance as of January 31, 2010 modified, as detailed below, to reflect that current rates (through April 30, 2010) include a credit for the overcollection as of January 31, 2009 and to reflect accruals for RPS. Figure is then allocated between rate periods (May-October 2010 and November 2010-April 2011) and then to each month, May through October 2010, on equal per kWh basis.

January 31, 2010 actual balance - Schedule LSM-2, Page 2	($1,143,483)	
less: Estimated remaining credit for January 31, 2009 reconciliation - Feb, Mar, Apr 2010		
Estimated kWh Sales Feb-Apr 2010	222,602,247	
Amount of reconciliation in current rate	($0.00002)	
Estimated amount of reconciliation to be credited Feb-Apr 2010	($4,452)	
plus: Non-G1 Class RPS amounts included in rate filings, Jan - Jul 2009	$914,358	Note: effective August 1, 2009, RPS moved to a separate reconciliation model
Total reconciliation for May 1, 2010-April 30, 2011	($224,673)	
kWh purchases forecast May-October 2010	443,568,800	50.45%
kWh purchases forecast November 2010-April 2011	435,727,296	49.55%
Total	879,296,096	
Reconciliation amount for May-October 2010	($113,347)	
Reconciliation amount for November 2010-April 2011	($111,325)	
Total	($224,673)	

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

Schedule LSM-2
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	(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)
Feb-09	($1,259,276)	$8,010,638	$7,536,393	($785,031)	($1,022,153)	4.00%	28	($3,136)	($788,168)
Mar-09	($788,168)	$7,205,121	$7,379,748	($962,794)	($875,481)	4.00%	31	($2,974)	($965,769)
Apr-09	($965,769)	$5,861,733	$6,460,062	($1,564,098)	($1,264,933)	3.25%	30	($3,379)	($1,567,477)
May-09	($1,567,477)	$4,776,088	$5,044,696	($1,836,084)	($1,701,780)	3.25%	31	($4,697)	($1,840,782)
Jun-09	($1,840,782)	$4,306,047	$5,070,023	($2,604,758)	($2,222,770)	3.25%	30	($5,938)	($2,610,696)
Jul-09	($2,610,696)	$7,667,120	$6,570,701	($1,514,277)	($2,062,486)	3.25%	31	($5,693)	($1,519,970)
Aug-09	($1,519,970)	$7,315,689	$6,242,669	($446,950)	($983,460)	3.25%	31	($2,715)	($449,664)
Sep-09	($449,664)	$4,764,103	$5,619,865	($1,305,426)	($877,545)	3.25%	30	($2,344)	($1,307,770)
Oct-09	($1,307,770)	$4,823,903	$4,564,453	($1,048,320)	($1,178,045)	3.25%	31	($3,252)	($1,051,572)
Nov-09	($1,051,572)	$3,785,214	$5,093,032	($2,359,390)	($1,705,481)	3.25%	30	($4,311) (1)	($2,363,701)
Dec-09	($2,363,701)	$7,206,908	$6,389,248	($1,546,040)	($1,954,870)	3.25%	31	($5,723) (2)	($1,551,763)
Jan-10	($1,551,763)	$7,080,371	$6,668,377	($1,139,768)	($1,345,765)	3.25%	31	($3,715)	($1,143,483)
Total		$72,802,935	$72,639,267					($47,876)	

(1) Includes $245.02 to adjust interest related to adjustment made to working capital (see page 3).
(2) Includes ($326.56) to adjust interest related to adjustment made to working capital (see page 3).

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	Calculation of Working Capital Supplier Charges and GIS Support Payments							Calculation of Working Capital Renewable Energy Credits								
	(a) Total Non-G1 Class DS Supplier Charges	(b) GIS Support Payments	(c) Number of Days of Lag / 365	(d) Working Capital Requirement ((a+b)*c)	(e) Prime Rate	(f) Supply Related Working Capital (d * e)	(g) Renewable Energy Credits	(h) Number of Days of Lead / 365	(i) Working Capital Requirement (g * -h)	(j) Prime Rate	(k) Supply Related Working Capital (i * j)	(l) Provision for Uncollected Accounts	(m) Internal Company Administrative Costs	(n) Legal Charges	(o) Consulting Outside Service Charges	(p) Total Costs (sum a + b + f + g + k + l + m + n + o)
Feb-09	$7,970,952	$659	2.81%	$223,860	4.00%	$8,954	$11,640	99.31%	($11,559)	4.00%	($462)	$15,603	$2,366	$0	$927	$8,010,638
Mar-09	$7,148,430	$740	2.81%	$200,764	4.00%	$8,031	$0	99.31%	$0	4.00%	$0	$45,065	$2,366	$0	$490	$7,205,121
Apr-09	$5,718,491	$609	2.81%	$160,605	3.25%	$5,220	$108,021	99.31%	($107,275)	3.25%	($3,486)	$30,512	$2,366	$0	$0	$5,861,733
May-09	$4,635,395	$596	2.81%	$130,189	3.25%	$4,231	$53,111	99.31%	($52,744)	3.25%	($1,714)	$41,175	$2,366	$0	$40,929	$4,776,088
Jun-09	$4,037,195	$535	2.81%	$113,388	3.25%	$3,685	$243,929	99.31%	($242,245)	3.25%	($7,873)	$26,210	$2,366	$0	$0	$4,306,047
Jul-09	$7,175,952	$535	2.81%	$201,531	3.25%	$6,550	$468,635	99.31%	($465,400)	3.25%	($15,125)	$28,208	$2,366	$0	$0	$7,667,120
Aug-09	$7,267,263	$682	2.81%	$204,100	3.25%	$6,633						$38,746	$2,366	$0	$0	$7,315,689
Sep-09	$4,732,898	$656	2.81%	$132,929	3.25%	$4,320						$23,863	$2,366	$0	$0	$4,764,103
Oct-09	$4,780,252	$698	2.81%	$134,260	3.25%	$4,363						$36,224	$2,366	$0	$0	$4,823,903
Nov-09	$3,728,391	$536	4.61%	$171,735	3.25%	$29,213 (1)						$24,956	$2,118	$0	$0	$3,785,214
Dec-09	$7,175,280	$542	4.61%	$330,481	3.25%	$816 (2)						$28,152	$2,118	$0	$0	$7,206,908
Jan-10	$7,050,326	$553	4.61%	$324,727	3.25%	$10,554						$16,821	$2,118	$0	$0	$7,080,371
Total	$71,420,825	$7,341		$2,328,569		$92,570	$885,337		($879,224)		($28,661)	$355,535	$27,644	$0	$42,346	$72,802,935

(1) Includes $23,631.46 to adjust working capital for the period May-October 2009 to use 16.81 days lag from the 2008 Lead/Lag Study.

(2) Includes ($9,924.91) to adjust working capital for the period November 2008-March 2009 based on the prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and fixed on a monthly basis, as ordered in DG 07-072 by Order No. 25,028.

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	(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 DSC (3)	(e) Non-G1 Class Unbilled Default Service Revenue (c * d)	(f) Reversal of prior month unbilled	(g) Total Billed Non-G1 Class Default Service Revenue (1)	(h) Total Revenue (e + f + g)
Feb-09	71,687,177	48.36%	34,667,967	$0.11239	$3,896,333	($4,439,885)	$8,079,946	$7,536,393
Mar-09	65,398,487	53.29%	34,851,079	$0.11239	$3,916,913	($3,896,333)	$7,359,168	$7,379,748
Apr-09	63,320,789	46.03%	29,143,948	$0.11239	$3,275,488	($3,916,913)	$7,101,486	$6,460,062
May-09	56,687,087	53.95%	30,580,273	$0.08618	$2,635,408	($3,275,488)	$5,684,776	$5,044,696
Jun-09	58,973,191	51.68%	30,476,083	$0.08618	$2,626,429	($2,635,408)	$5,079,002	$5,070,023
Jul-09	67,392,122	58.32%	39,306,023	$0.08618	$3,387,393	($2,626,429)	$5,809,737	$6,570,701
Aug-09	74,608,777	51.77%	38,625,156	$0.08439	$3,259,577	($3,387,393)	$6,370,485	$6,242,669
Sep-09	70,310,571	49.63%	34,891,961	$0.08439	$2,944,533	($3,259,577)	$5,934,909	$5,619,865
Oct-09	58,228,492	52.84%	30,765,122	$0.08439	$2,596,269	($2,944,533)	$4,912,717	$4,564,453
Nov-09	57,631,318	53.74%	30,971,292	$0.08825	$2,733,217	($2,596,269)	$4,956,084	$5,093,032
Dec-09	64,628,025	60.03%	38,796,520	$0.08825	$3,423,793	($2,733,217)	$5,698,671	$6,389,248
Jan-10	78,092,243	46.40%	36,236,288	$0.08825	$3,197,852	($3,423,793)	$6,894,317	$6,668,377
Total	786,958,279				$37,893,204	($39,135,237)	$73,881,300	$72,639,267

(1) Per billing system
(2) Detail of Unbilled Factors for the Residential, Regular General, and Outdoor Lighting Classes:
(3) Beginning in August 2009, rate shown is "Fixed Power Supply Charge".

	Billed kWh	Direct Estimate of Unbilled kWh	Unbilled kWh / Billed kWh
Feb-09	74,129,599	35,849,124	48.36%
Mar-09	67,763,862	36,111,595	53.29%
Apr-09	65,825,524	30,296,774	46.03%
May-09	59,199,422	31,935,571	53.95%
Jun-09	61,853,147	31,964,383	51.68%
Jul-09	70,532,225	41,137,468	58.32%
Aug-09	78,861,225	40,826,659	51.77%
Sep-09	75,192,954	37,314,868	49.63%
Oct-09	62,796,629	33,178,705	52.84%
Nov-09	62,064,126	33,353,500	53.74%
Dec-09	69,589,063	41,774,655	60.03%
Jan-10	84,233,155	39,085,788	46.40%

	(a) Total Non-G1 Class DS Supplier Charges (1)	(b) GIS Support Payments	*Calculation of Working Capital Supplier Charges and GIS Support Payments* (c) Number of Days of Lag / 365	(d) Working Capital Requirement ((a+b)*c)	(e) Prime Rate	(f) Supply Related Working Capital (d * e)	(g) Provision for Uncollected Accounts	(h) Internal Company Administrative Costs	(i) Legal Charges	(j) Consulting Outside Service Charges	(k) Total Costs (sum a + b + f + g + h + i + j)
May-10	$4,669,000	$553	4.36%	$203,413	3.25%	$6,611	$43,200	$2,118	$0	$0	$4,721,482
Jun-10	$5,472,500	$632	4.36%	$238,419	3.25%	$7,749	$47,520	$2,118	$0	$0	$5,530,518
Jul-10	$6,770,401	$748	4.36%	$294,962	3.25%	$9,586	$47,520	$2,118	$0	$0	$6,830,374
Aug-10	$6,928,211	$744	4.36%	$301,837	3.25%	$9,810	$47,520	$2,118	$0	$0	$6,988,403
Sep-10	$5,250,425	$611	4.36%	$228,744	3.25%	$7,434	$38,880	$2,118	$0	$0	$5,299,468
Oct-10	$5,245,390	$601	4.36%	$228,524	3.25%	$7,427	$30,240	$2,118	$0	$0	$5,285,776
Total	$34,335,927	$3,889		$1,495,899		$48,617	$254,880	$12,708	$0	$0	$34,656,022

(1) Estimates based on monthly average wholesale rate times estimated monthly purchases.

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

		May-10 Estimated	Jun-10 Estimated	Jul-10 Estimated	Aug-10 Estimated	Sep-10 Estimated	Oct-10 Estimated	Total
1	Reconciliation	$1,551	$1,775	$2,101	$2,090	$1,715	$1,688	$10,921
2	Total Costs (Page 2)	$118,486	$135,627	$160,474	$159,619	$131,029	$128,975	$834,210
3	Reconciliation plus Total Costs (L.1 + L.2)	$120,037	$137,402	$162,575	$161,709	$132,744	$130,663	$845,131
4	kWh Purchases	63,001,518	72,116,000	85,328,322	84,873,727	69,670,112	68,579,121	443,568,800
5	Total, Before Losses (L.3 / L.4)	$0.00191	$0.00191	$0.00191	$0.00191	$0.00191	$0.00191	$0.00191
6	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
	Total Retail Rate - Variable RPS Charge (L.5 * (1+L.6))	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	
	Total Retail Rate - Fixed RPS Charge (L.5 * (1+L.6))							$0.00203

(1) Balance as of January 31, 2010 modified, as detailed below, to reflect accruals for RPS. Figure is then allocated between rate periods (May-October 2010 and November 2010-April 2011) and then to each month, May through October 2010, on equal per kWh basis.

January 31, 2010 actual balance - Schedule LSM-3, Page 2	($636,659)	
plus: Non-G1 Class RPS amounts included in rate filings, Aug 2009-Jan 2010	$801,297	
less: Non-G1 Class RPS amounts, CY 2009 requirement, purchased	$142,992	
Net Non-G1 Class RPS amounts included in rate filings, Aug 2009-Jan 2010	$658,305	
Total reconciliation for May 1, 2010-April 30, 2011	$21,646	
kWh purchases forecast May-October 2010	443,568,800	50.45%
kWh purchases forecast November 2010-April 2011	435,727,296	49.55%
Total	879,296,096	
Reconciliation amount for May-October 2010	$10,921	
Reconciliation amount for November 2010-April 2011	$10,726	
Total	$21,646	

	(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)
Aug-09	$0	$6,830	$131,974	($125,144)	($62,572)	3.25%	31	($173)	($125,316)
Sep-09	($125,316)	$0	$119,103	($244,419)	($184,868)	3.25%	30	($494)	($244,913)
Oct-09	($244,913)	$0	$96,847	($341,760)	($293,337)	3.25%	31	($810)	($342,570)
Nov-09	($342,570)	$6,173	$121,851	($458,248)	($400,409)	3.25%	30	($1,070)	($459,317)
Dec-09	($459,317)	$80,464	$153,338	($532,191)	($495,754)	3.25%	31	($1,368)	($533,560)
Jan-10	($533,560)	$58,554	$160,040	($635,046)	($584,303)	3.25%	31	($1,613)	($636,659)
Total		$152,020	$783,152					($5,527)	

Unitil Energy Systems, Inc.
Itemized Costs for Non-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	Working Capital Requirement (a*b)	Prime Rate	Supply Related Working Capital (c * d)	Total Costs (sum a + e)
Aug-09	$7,025	(85.52%)	($6,008)	3.25%	($195)	$6,830
Sep-09	$0	(85.52%)	$0	3.25%	$0	$0
Oct-09	$0	(85.52%)	$0	3.25%	$0	$0
Nov-09	$6,349	(85.52%)	($5,430)	3.25%	($176)	$6,173
Dec-09	$82,764	(85.52%)	($70,778)	3.25%	($2,300)	$80,464
Jan-10	$60,227	(85.52%)	($51,505)	3.25%	($1,674)	$58,554
Total	$156,366		($133,721)		($4,346)	$152,020

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	(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)
Aug-09	74,608,777	51.77%	38,625,156	$0.00179	$69,139	$0	$62,835	$131,974
Sep-09	70,310,571	49.63%	34,891,961	$0.00179	$62,457	($69,139)	$125,785	$119,103
Oct-09	58,228,492	52.84%	30,765,122	$0.00179	$55,070	($62,457)	$104,234	$96,847
Nov-09	57,631,318	53.74%	30,971,292	$0.00212	$65,659	($55,070)	$111,261	$121,851
Dec-09	64,628,025	60.03%	38,796,520	$0.00212	$82,249	($65,659)	$136,748	$153,338
Jan-10	78,092,243	46.40%	36,236,288	$0.00212	$76,821	($82,249)	$165,468	$160,040
Total	403,499,426				$411,394	($334,573)	$706,331	$783,152

(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
Aug-09	78,861,225	40,826,659	51.77%
Sep-09	75,192,954	37,314,868	49.63%
Oct-09	62,796,629	33,178,705	52.84%
Nov-09	62,064,126	33,353,500	53.74%
Dec-09	69,589,063	41,774,655	60.03%
Jan-10	84,233,155	39,085,788	46.40%

Unitil Energy Systems, Inc.
Itemized Costs for Non-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	Working Capital Requirement (a*b)	Prime Rate	Supply Related Working Capital (c * d)	Total Costs (sum a + e)
May-10	$121,757	(82.65%)	($100,631)	3.25%	($3,271)	$118,486
Jun-10	$139,370	(82.65%)	($115,189)	3.25%	($3,744)	$135,627
Jul-10	$164,904	(82.65%)	($136,292)	3.25%	($4,429)	$160,474
Aug-10	$164,025	(82.65%)	($135,566)	3.25%	($4,406)	$159,619
Sep-10	$134,645	(82.65%)	($111,283)	3.25%	($3,617)	$131,029
Oct-10	$132,535	(82.65%)	($109,539)	3.25%	($3,560)	$128,975
Total	$857,236		($708,500)		($23,026)	$834,210

(1) Schedule RSF-4.

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

		May-10 Estimated	Jun-10 Estimated	Jul-10 Estimated	Total
1	Reconciliation (1)	($2,830)	($2,543)	($3,178)	($8,550)
2	Total Costs (Page 2)	$752,196	$652,785	$843,245	$2,248,225
3	Reconciliation plus Total Costs (L.1 + L.2)	$749,366	$650,242	$840,067	$2,239,675
4	kWh Purchases	11,344,763	10,194,853	12,739,542	34,279,157
5	Total, Before Losses (L.3 / L.4)	$0.06605	$0.06378	$0.06594	
6	Losses	4.591%	4.591%	4.591%	
7	Total Retail Rate - Variable Power Supply Charge (L.5 * (1+L.6))	$0.06909	$0.06671	$0.06897	

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(1) Balance as of January 31, 2010 modified, as detailed below, to reflect that current rates (through April 30, 2010) include a charge for the undercollection as of January 31, 2009 and to reflect accruals for RPS. Figure is then allocated between rate periods (May-July 2010, August-October 2010, November 2010-January 2011, and February-April 2011) and then to each month, May through July 2010, on equal per kWh basis.

January 31, 2010 actual balance - Schedule LSM-4, Page 2	($28,632)	
less: Estimated remaining charge for January 31, 2009 reconciliation - Feb, Mar, Apr 2010		
Estimated kWh Sales February-April 2010	28,703,892	
Amount of reconciliation in current rate	$0.00363	
Estimated amount of reconciliation to be collected Feb-Apr 2010	$104,195	
plus: G1 Class RPS amounts included in rate filings, Jan-Jul 2009	$100,577	Note: effective August 1, 2009, RPS moved to a separate reconciliation model
Total reconciliation for May 1, 2010-April 30, 2011	($32,250)	
kWh purchases forecast May-July 2010	34,279,157	26.51%
kWh purchases forecast August-October 2010	34,094,607	26.37%
kWh purchases forecast November 2010-January 2011	30,519,380	23.60%
kWh purchases forecast February-April 2011	30,401,228	23.51%
Total	129,294,371	
Reconciliation amount for May-July 2010	($8,550)	
Reconciliation amount for August-October 2010	($8,504)	
Reconciliation amount for November 2010-January 2011	($7,612)	
Reconciliation amount for February-April 2011	($7,583)	
Total	($32,250)	

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)
Feb-09	$409,839	$1,062,393	$936,548	$535,684	$472,761	4.00%	28	$1,451	$537,134
Mar-09	$537,134	$855,020	$867,964	$524,191	$530,662	4.00%	31	$1,803	$525,993
Apr-09	$525,993	$809,528	$833,228	$502,294	$514,144	3.25%	30	$1,373	$503,667
May-09	$503,667	$549,403	$628,686	$424,384	$464,026	3.25%	31	$1,281	$425,665
Jun-09	$425,665	$443,117	$727,126	$141,656	$283,661	3.25%	30	$758	$142,414
Jul-09	$142,414	$772,785	$843,562	$71,637	$107,026	3.25%	31	$295	$71,933
Aug-09	$71,933	$421,332	$336,919	$156,346	$114,139	3.25%	31	$315	$156,661
Sep-09	$156,661	$366,657	$459,088	$64,230	$110,445	3.25%	30	$295	$64,525
Oct-09	$64,525	$393,506	$365,866	$92,165	$78,345	3.25%	31	$216	$92,381
Nov-09	$92,381	$356,745	$377,526	$71,600	$81,990	3.25%	30	$206 (1)	$71,806
Dec-09	$71,806	$390,538	$411,851	$50,493	$61,150	3.25%	31	$106 (2)	$50,599
Jan-10	$50,599	$421,732	$500,994	($28,662)	$10,968	3.25%	31	$30	($28,632)
Total		$6,842,757	$7,289,357					$8,129	

(1) Includes ($12.60) to adjust interest related to adjustment made to working capital (see page 3).
(2) Includes ($63.16) to adjust interest related to adjustment made to working capital (see page 3).

Redacted

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

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
			Calculation of Working Capital Supplier Charges and GIS Support Payments					*Calculation of Working Capital Renewable Energy Credits*								
	Total G1 Class DS Supplier Charges	GIS Support Payments	Number of Days of Lag / 365	Working Capital Requirement ((a+b)*c)	Prime Rate	Supply Related Working Capital (d * e)	Renewable Energy Credits	Number of Days of Lead / 365	Working Capital Requirement (g * -h)	Prime Rate	Supply Related Working Capital (i * j)	Provision for Uncollected Accounts	Internal Company Administrative Costs	Legal Charges	Consulting Outside Service Charges	Total Costs (sum a + b + f + g + k + l + m + n + o)
Feb-09	$1,053,681	$81	3.70%	$38,946	4.00%	$1,558	$1,560	$1	($1,564)	$0	($63)	$1,924	$3,537	$0	$114	$1,062,393
Mar-09	$844,040	$99	3.70%	$31,198	4.00%	$1,248	$0	$1	$0	$0	$0	$6,031	$3,537	$0	$66	$855,020
Apr-09	$786,486	$89	3.70%	$29,071	3.25%	$945	$14,479	$1	($14,512)	$0	($472)	$4,463	$3,537	$0	$0	$809,528
May-09	$525,253	$94	3.70%	$19,416	3.25%	$631	$7,119	$1	($7,135)	$0	($232)	$6,520	$3,537	$0	$6,481	$549,403
Jun-09	$402,988	$90	3.70%	$14,897	3.25%	$484	$32,696	$1	($32,770)	$0	($1,065)	$4,387	$3,537	$0	$0	$443,117
Jul-09	$703,170	$83	3.70%	$25,991	3.25%	$845	$62,815	$1	($62,958)	$0	($2,046)	$4,382	$3,537	$0	$0	$772,785
Aug-09	$413,724	$62	3.70%	$15,293	3.25%	$497						$3,511	$3,537	$0	$0	$421,332
Sep-09	$360,451	$60	3.70%	$13,324	3.25%	$433						$2,176	$3,537	$0	$0	$366,657
Oct-09	$385,861	$69	3.70%	$14,264	3.25%	$464						$3,575	$3,537	$0	$0	$393,506
Nov-09	$352,209	$50	1.93%	$6,814	3.25%	($1,040)(1)						$2,349	$3,177	$0	$0	$356,745
Dec-09	$386,719	$43	1.93%	$7,481	3.25%	($1,642)(2)						$2,242	$3,177	$0	$0	$390,538
Jan-10	Redacted	$40	1.93%	Redacted	3.25%	Redacted						Redacted	$3,177	$0	$0	$421,732
Total	Redacted	$861		Redacted		Redacted	$118,668	$0	($118,938)	$0	($3,877)	Redacted	$41,365	$0	$6,661	$6,842,757

(1) Includes ($1,261.36) to adjust working capital for the period May-October 2009 to use 7.06 days lag from the 2008 Lead/Lag Study.
(2) Includes ($1,885.52) to adjust working capital for the period November 2008-March 2009 based on the prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and fixed on a monthly basis, as ordered in DG 07-072 by Order No. 25,028.

	(a) Total G1 Class Billed Default Service kWh (1)	(b) Unbilled Factor (2)	(c) G1 Class Unbilled kWh (a * b)	(d) Effective DSC (3)	(e) G1 Class Unbilled Default Service Revenue (c * d)	(f) Reversal of prior month unbilled	(g) Total Billed G1 Class Default Service Revenue (1)	(h) Total Revenue (e + f + g)
Feb-09	8,840,988	50.36%	4,452,582	$0.10811	$481,369	($553,967)	$1,009,146	$936,548
Mar-09	8,751,605	56.25%	4,922,778	$0.09527	$468,993	($481,369)	$880,339	$867,964
Apr-09	9,262,873	48.64%	4,505,288	$0.09431	$424,894	($468,993)	$877,327	$833,228
May-09	8,976,128	53.44%	4,796,450	$0.06988	$335,176	($424,894)	$718,403	$628,686
Jun-09	9,871,227	50.66%	5,000,986	$0.07213	$360,721	($335,176)	$701,581	$727,126
Jul-09	10,469,114	48.11%	5,036,352	$0.07982	$402,002	($360,721)	$802,281	$843,562
Aug-09	6,761,726	49.43%	3,342,052	$0.06987	$233,509	($402,002)	$505,412	$336,919
Sep-09	6,410,972	57.11%	3,661,515	$0.06821	$249,752	($233,509)	$442,845	$459,088
Oct-09	5,747,300	51.07%	2,934,992	$0.07227	$212,112	($249,752)	$403,506	$365,866
Nov-09	5,424,048	53.04%	2,877,136	$0.07035	$202,406	($212,112)	$387,232	$377,526
Dec-09	5,147,961	54.93%	2,827,998	$0.08077	$228,417	($202,406)	$385,840	$411,851
Jan-10	5,680,442	47.49%	2,697,514	$0.09073	$244,745	($228,417)	$484,666	$500,994
Total	91,344,383				$3,844,096	($4,153,318)	$7,598,579	$7,289,357

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(1) Per billing system
(2) Detail of Unbilled Factors for the Large General Class:
(3) Beginning in August 2009, rate shown is "Variable Power Supply Charge".

	Billed kWh	Direct Estimate of Unbilled kWh	Unbilled kWh / Billed kWh
Feb-09	28,080,876	14,142,356	50.36%
Mar-09	26,951,031	15,159,955	56.25%
Apr-09	27,926,042	13,582,705	48.64%
May-09	27,738,173	14,822,066	53.44%
Jun-09	28,584,069	14,481,333	50.66%
Jul-09	31,048,428	14,936,395	48.11%
Aug-09	32,371,261	15,999,826	49.43%
Sep-09	31,169,381	17,801,850	57.11%
Oct-09	28,729,567	14,671,421	51.07%
Nov-09	28,037,649	14,872,308	53.04%
Dec-09	28,372,560	15,586,273	54.93%
Jan-10	28,962,938	13,753,846	47.49%

Redacted

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)
	Total G1 Class DS Supplier Charges (1)	GIS Support Payments	Number of Days of Lag / 365	Working Capital Requirement ((a+b)*c)	Prime Rate	Supply Related Working Capital (d * e)	Provision for Uncollected Accounts	Internal Company Administrative Costs	Legal Charges	Consulting Outside Service Charges	Total Costs (sum a + b + f + g + h + i + j)
May-10	Redacted	$99	3.76%	Redacted	3.25%	Redacted	Redacted	$3,177	$0	$0	$752,196
Jun-10	Redacted	$89	3.76%	Redacted	3.25%	Redacted	Redacted	$3,177	$0	$0	$652,785
Jul-10	Redacted	$112	3.76%	Redacted	3.25%	Redacted	Redacted	$3,177	$0	$0	$843,245
Total	Redacted	$301		Redacted		Redacted	Redacted	$9,530	$0	$0	$2,248,225

(1) Estimates based on monthly average wholesale rate times estimated monthly purchases.

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

		May-10 Estimated	Jun-10 Estimated	Jul-10 Estimated	Total
1	Reconciliation	$4,315	$3,877	$4,845	$13,038
2	Total Costs (Page 2)	$21,720	$19,519	$24,391	$65,630
3	Reconciliation plus Total Costs (L.1 + L.2)	$26,035	$23,396	$29,236	$78,668
4	kWh Purchases	11,344,763	10,194,853	12,739,542	34,279,157
5	Total, Before Losses (L.3 / L.4)	$0.00229	$0.00229	$0.00229	
6	Losses	4.591%	4.591%	4.591%	
7	Total Retail Rate - Variable RPS Charge (L.5 * (1+L.6))	$0.00240	$0.00240	$0.00240	

(1) Balance as of January 31, 2010 modified, as detailed below, to reflect accruals for RPS. Figure is then allocated between rate periods (May-July 2010, August-October 2010, November 2010-January 2011, and February-April 2011) and then to each month, May through July 2010, on equal per kWh basis.

January 31, 2010 actual balance - Schedule LSM-5, Page 2	($46,999)	
plus: G1 Class RPS amounts included in rate filings, August 2009-Jan 2010	$96,175	
less: G1 Class RPS amounts, CY 2009 requirement, purchased	$18,366	
Net G1 Class RPS amounts included in rate filings, Aug 2009-Jan 2010	$77,809	
Total reconciliation for May 1, 2009-April 30, 2010	$49,175	
kWh purchases forecast May-July 2010	34,279,157	26.51%
kWh purchases forecast August-October 2010	34,094,607	26.37%
kWh purchases forecast November 2010-January 2011	30,519,380	23.60%
kWh purchases forecast February-April 2011	30,401,228	23.51%
Total	129,294,371	
Reconciliation amount for May-July 2010	$13,038	
Reconciliation amount for August-October 2010	$12,967	
Reconciliation amount for November 2010-January 2011	$11,608	
Reconciliation amount for February-April 2011	$11,563	
Total	$49,175	

Unitil Energy Systems, Inc.
Reconciliation of 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)
Aug-09	$0	$915	$13,105	($12,191)	($6,095)	3.25%	31	($17)	($12,207)
Sep-09	($12,207)	$0	$12,990	($25,197)	($18,702)	3.25%	30	($50)	($25,247)
Oct-09	($25,247)	$0	$9,690	($34,937)	($30,092)	3.25%	31	($83)	($35,020)
Nov-09	($35,020)	$827	$9,231	($43,425)	($39,223)	3.25%	30	($105)	($43,530)
Dec-09	($43,530)	$10,775	$8,770	($41,525)	($42,527)	3.25%	31	($117)	($41,642)
Jan-10	($41,642)	$7,064	$12,299	($46,877)	($44,260)	3.25%	31	($122)	($46,999)
Total		$19,580	$66,085					($494)	

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	Working Capital Requirement (a*b)	Prime Rate	Supply Related Working Capital (c * d)	Total Costs (sum a + e)
Aug-09	$942	(88.35%)	($832)	3.25%	($27)	$915
Sep-09	$0	(88.35%)	$0	3.25%	$0	$0
Oct-09	$0	(88.35%)	$0	3.25%	$0	$0
Nov-09	$851	(88.35%)	($752)	3.25%	($24)	$827
Dec-09	$11,093	(88.35%)	($9,801)	3.25%	($319)	$10,775
Jan-10	$7,273	(88.35%)	($6,425)	3.25%	($209)	$7,064
Total	$20,159		($17,810)		($579)	$19,580

	(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 RPS Charge	G1 Class Unbilled RPS Charge Revenue (c * d)	Reversal of prior month unbilled	Total Billed G1 Class RPS Charge Revenue (1)	Total Revenue (e + f + g)
Aug-09	6,761,726	49.43%	3,342,052	$0.00193	$6,450	$0	$6,655	$13,105
Sep-09	6,410,972	57.11%	3,661,515	$0.00193	$7,067	($6,450)	$12,373	$12,990
Oct-09	5,747,300	51.07%	2,934,992	$0.00193	$5,665	($7,067)	$11,092	$9,690
Nov-09	5,424,048	53.04%	2,877,136	$0.00172	$4,949	($5,665)	$9,947	$9,231
Dec-09	5,147,961	54.93%	2,827,998	$0.00172	$4,864	($4,949)	$8,855	$8,770
Jan-10	5,680,442	47.49%	2,697,514	$0.00224	$6,042	($4,864)	$11,120	$12,299
Total	35,172,449				$35,037	($28,994)	$60,043	$66,085

(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
Aug-09	32,371,261	15,999,826	49.43%
Sep-09	31,169,381	17,801,850	57.11%
Oct-09	28,729,567	14,671,421	51.07%
Nov-09	28,037,649	14,872,308	53.04%
Dec-09	28,372,560	15,586,273	54.93%
Jan-10	28,962,938	13,753,846	47.49%

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

	(a)	*Calculation of Working Capital* (b)	(c)	(d)	(e)	(f)
	Renewable Energy Credits (1)	Number of Days of Lag / 365	Working Capital Requirement (a*b)	Prime Rate	Supply Related Working Capital (c * d)	Total Costs (sum a + e)
May-10	$22,312	(81.55%)	($18,195)	3.25%	($591)	$21,720
Jun-10	$20,050	(81.55%)	($16,351)	3.25%	($531)	$19,519
Jul-10	$25,055	(81.55%)	($20,432)	3.25%	($664)	$24,391
Total	$67,417		($54,979)		($1,787)	$65,630

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(1) Schedule RSF-4.

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

Residential Rate D 500 kWh Bill

	2/1/2010	5/1/2010					%
Rate Components	Current Rate	As Revised	Difference	Current Bill*	As Revised Bill*	Difference	Difference to Total Bill
Customer Charge	$8.40	$8.40	$0.00	$8.40	$8.40	$0.00	0.0%
	$/kWh	$/kWh					
Distribution Charge							
First 250 kWh	$0.01810	$0.01810	$0.00000	$4.53	$4.53	$0.00	0.0%
Excess 250 kWh	$0.02310	$0.02310	$0.00000	$5.78	$5.78	$0.00	0.0%
External Delivery Charge	$0.01425	$0.01425	$0.00000	$7.13	$7.13	$0.00	0.0%
Stranded Cost Charge	$0.00495	$0.00495	$0.00000	$2.48	$2.48	$0.00	0.0%
System Benefits Charge	$0.00330	$0.00330	$0.00000	$1.65	$1.65	$0.00	0.0%
Default Service Charge	$0.09037	$0.08489	($0.00548)	$45.19	$42.45	($2.74)	-3.6%
First 250 kWh	$0.13097	$0.12549	($0.00548)				
Excess 250 kWh	$0.13597	$0.13049	($0.00548)				
Total Bill				$75.14	$72.40	($2.74)	-3.6%

* Impacts do not include the Electricity Consumption Tax.

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

Regular General G2 Quick Recovery Water Heating and Space Heating 2,000 kWh Typical Bill

Rate Components	2/1/2010 Current Rate	5/1/2010 As Revised	Difference	Current Bill*	As Revised Bill*	Difference	% Difference to Total Bill
Customer Charge	$3.75	$3.75	$0.00	$3.75	$3.75	$0.00	0.0%
	$/kWh	**$/kWh**					
Distribution Charge	$0.02088	$0.02088	$0.00000	$41.76	$41.76	$0.00	0.0%
External Delivery Charge	$0.01425	$0.01425	$0.00000	$28.50	$28.50	$0.00	0.0%
Stranded Cost Charge	$0.00495	$0.00495	$0.00000	$9.90	$9.90	$0.00	0.0%
System Benefits Charge	$0.00330	$0.00330	$0.00000	$6.60	$6.60	$0.00	0.0%
Default Service Charge	$0.09037	$0.08489	($0.00548)	$180.74	$169.78	($10.96)	-4.0%
Total	$0.13375	$0.12827	($0.00548)	$267.50	$256.54	($10.96)	-4.0%
Total Bill				$271.25	$260.29	($10.96)	-4.0%

Regular General G2 kWh Meter 125 kWh Typical Bill

Rate Components	2/1/2010 Current Rate	5/1/2010 As Revised	Difference	Current Bill*	As Revised Bill*	Difference	% Difference to Total Bill
Customer Charge	$8.40	$8.40	$0.00	$8.40	$8.40	$0.00	0.0%
	$/kWh	**$/kWh**					
Distribution Charge	$0.02975	$0.02975	$0.00000	$3.72	$3.72	$0.00	0.0%
External Delivery Charge	$0.01425	$0.01425	$0.00000	$1.78	$1.78	$0.00	0.0%
Stranded Cost Charge	$0.00495	$0.00495	$0.00000	$0.62	$0.62	$0.00	0.0%
System Benefits Charge	$0.00330	$0.00330	$0.00000	$0.41	$0.41	$0.00	0.0%
Default Service Charge	$0.09037	$0.08489	($0.00548)	$11.30	$10.61	($0.69)	-2.6%
Total	$0.14262	$0.13714	($0.00548)	$17.83	$17.14	($0.69)	-2.6%
Total Bill				$26.23	$25.54	($0.69)	-2.6%

* Impacts do not include the Electricity Consumption Tax.

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

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Regular General G2 Demand, 10 kW, 3,000 kWh Typical Bill

Rate Components	2/1/2010 Current Rate	5/1/2010 As revised	Difference	Current Bill*	As Revised Bill*	Difference	% Difference to Total Bill
Customer Charge	$11.00	$11.00	$0.00	$11.00	$11.00	$0.00	0.0%
	All kW	All kW					
Distribution Charge	$7.03	$7.03	$0.00	$70.30	$70.30	$0.00	0.0%
Stranded Cost Charge	$0.87	$0.87	$0.00	$8.70	$8.70	$0.00	0.0%
Total	$7.90	$7.90	$0.00	$79.00	$79.00	$0.00	0.0%
	$/kWh	$/kWh					
Distribution Charge	$0.00000	$0.00000	$0.00000	$0.00	$0.00	$0.00	0.0%
External Delivery Charge	$0.01425	$0.01425	$0.00000	$42.75	$42.75	$0.00	0.0%
Stranded Cost Charge	$0.00167	$0.00167	$0.00000	$5.01	$5.01	$0.00	0.0%
System Benefits Charge	$0.00330	$0.00330	$0.00000	$9.90	$9.90	$0.00	0.0%
Default Service Charge	$0.09037	$0.08489	($0.00548)	$271.11	$254.67	($16.44)	-3.9%
Total	$0.10959	$0.10411	($0.00548)	$328.77	$312.33	($16.44)	-3.9%
Total Bill				$418.77	$402.33	($16.44)	-3.9%

Large General - G1 550 kVa, 200,000 kWh Typical Bill

Rate Components	2/1/2010 Current Rate	5/1/2010 As Revised	Difference	Current Bill*	As Revised Bill*	Difference	% Difference to Total Bill
Customer Charge	$108.86	$108.86	$0.00	$108.86	$108.86	$0.00	0.0%
	All kVa	All kVa					
Distribution Charge	$5.69	$5.69	$0.00	$3,129.50	$3,129.50	$0.00	0.0%
Stranded Cost Charge	$1.24	$1.24	$0.00	$682.00	$682.00	$0.00	0.0%
Total	$6.93	$6.93	$0.00	$3,811.50	$3,811.50	$0.00	0.0%
	$/kWh	$/kWh					
Distribution Charge	$0.00000	$0.00000	$0.00000	$0.00	$0.00	$0.00	0.0%
External Delivery Charge	$0.01425	$0.01425	$0.00000	$2,850.00	$2,850.00	$0.00	0.0%
Stranded Cost Charge	$0.00147	$0.00147	$0.00000	$294.00	$294.00	$0.00	0.0%
System Benefits Charge	$0.00330	$0.00330	$0.00000	$660.00	$660.00	$0.00	0.0%
Default Service Charge	$0.08812	$0.07066	($0.01746)	$17,624.00	$14,132.00	($3,492.00)	-13.8%
Total	$0.10714	$0.08968	($0.01746)	$21,428.00	$17,936.00	($3,492.00)	-13.8%
Total Bill				$25,348.36	$21,856.36	($3,492.00)	-13.8%

* Impacts do not include the Electricity Consumption Tax.

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

Residential Rate D 645 kWh Bill - Mean Use*

Rate Components	2/1/2010 Current Rate	5/1/2010 As Revised	Difference	Current Bill**	As Revised Bill**	Difference	% Difference to Total Bill
Customer Charge	$8.40	$8.40	$0.00	$8.40	$8.40	$0.00	0.0%
	$/kWh	$/kWh					
Distribution Charge							
First 250 kWh	$0.01810	$0.01810	$0.00000	$4.53	$4.53	$0.00	0.0%
Excess 250 kWh	$0.02310	$0.02310	$0.00000	$9.12	$9.12	$0.00	0.0%
External Delivery Charge	$0.01425	$0.01425	$0.00000	$9.19	$9.19	$0.00	0.0%
Stranded Cost Charge	$0.00495	$0.00495	$0.00000	$3.19	$3.19	$0.00	0.0%
System Benefits Charge	$0.00330	$0.00330	$0.00000	$2.13	$2.13	$0.00	0.0%
Default Service Charge	$0.09037	$0.08489	($0.00548)	$58.29	$54.75	($3.53)	-3.7%
First 250 kWh	$0.13097	$0.12549	($0.00548)				
Excess 250 kWh	$0.13597	$0.13049	($0.00548)				
Total Bill				$94.85	$91.32	($3.53)	-3.7%

Residential Rate D 540 kWh Bill - Median Use*

Rate Components	2/1/2010 Current Rate	5/1/2010 As Revised	Difference	Current Bill**	As Revised Bill**	Difference	% Difference to Total Bill
Customer Charge	$8.40	$8.40	$0.00	$8.40	$8.40	$0.00	0.0%
	$/kWh	$/kWh					
Distribution Charge							
First 250 kWh	$0.01810	$0.01810	$0.00000	$4.53	$4.53	$0.00	0.0%
Excess 250 kWh	$0.02310	$0.02310	$0.00000	$6.70	$6.70	$0.00	0.0%
External Delivery Charge	$0.01425	$0.01425	$0.00000	$7.70	$7.70	$0.00	0.0%
Stranded Cost Charge	$0.00495	$0.00495	$0.00000	$2.67	$2.67	$0.00	0.0%
System Benefits Charge	$0.00330	$0.00330	$0.00000	$1.78	$1.78	$0.00	0.0%
Default Service Charge	$0.09037	$0.08489	($0.00548)	$48.80	$45.84	($2.96)	-3.7%
First 250 kWh	$0.13097	$0.12549	($0.00548)				
Excess 250 kWh	$0.13597	$0.13049	($0.00548)				
Total Bill				$80.57	$77.61	($2.96)	-3.7%

* Based on billing period January through December 2009.
** Impacts do not include the Electricity Consumption Tax.

Unitil Energy Systems, Inc.
Average Class Bill Impacts
Due to Proposed Rate Changes Effective May 1, 2010

(A) Class of Service	(B) Number of Customers	(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	738,543	486,378,217	n/a	($2,665,353)	$71,492,071	$68,826,718	($2,665,353)	(3.7%)
General Service	125,046	354,008,286	1,298,686	($1,939,965)	$50,569,602	$48,629,637	($1,939,965)	(3.8%)
Large General Service	1,822	364,679,187	996,528	($6,367,299)	$46,006,880	$39,639,581	($6,367,299)	(13.8%)
Outdoor Lighting	117,884	9,206,974	n/a	($50,454)	$2,275,987	$2,225,533	($50,454)	(2.2%)
Total	983,295	1,214,272,664		($11,023,071)	$170,344,540	$159,321,469	($11,023,071)	(6.5%)

(B), (C), (D) Test year billing determinants in DE 05-178

(E) Difference in proposed rate and current rate, times the billing determinants shown in Column (C). The proposed and current DSC for the G1 class used in this analysis are based on the average of the DSC for each 3-month period.

(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 - February 1, 2010 versus May 1, 2010
Impacts do NOT include the Electricity Consumption Tax
Impact on D Rate Customers

Average kWh	Total Bill Using Rates 2/1/2010	Total Bill Using Rates 5/1/2010	Total Difference	% Total Difference
125	$24.77	$24.09	($0.69)	(2.8%)
250	$41.14	$39.77	($1.37)	(3.3%)
500	$75.14	$72.40	($2.74)	(3.6%)
600	$88.73	$85.44	($3.29)	(3.7%)
750	$109.13	$105.02	($4.11)	(3.8%)
1,000	$143.12	$137.64	($5.48)	(3.8%)
1,250	$177.11	$170.26	($6.85)	(3.9%)
1,500	$211.11	$202.89	($8.22)	(3.9%)
2,000	$279.09	$268.13	($10.96)	(3.9%)
3,500	$483.05	$463.87	($19.18)	(4.0%)
5,000	$687.00	$659.60	($27.40)	(4.0%)

		Rates - Effective February 1, 2010	Rates - Proposed May 1, 2010	Difference
Customer Charge		**$8.40**	**$8.40**	**$0.00**
		kWh	kWh	kWh
Distribution Charge:	First 250 kWh	$0.01810	$0.01810	$0.00000
	Excess 250 kWh	$0.02310	$0.02310	$0.00000
External Delivery Charge		$0.01425	$0.01425	$0.00000
Stranded Cost Charge		$0.00495	$0.00495	$0.00000
System Benefits Charge		$0.00330	$0.00330	$0.00000
Default Service Charge		$0.09037	$0.08489	($0.00548)
TOTAL	First 250 kWh	**$0.13097**	**$0.12549**	**($0.00548)**
	Excess 250 kWh	**$0.13597**	**$0.13049**	**($0.00548)**

Unitil Energy Systems, Inc.
Typical Bill Impacts - February 1, 2010 versus May 1, 2010
Impacts do NOT include the Electricity Consumption Tax
Impact on G2 Rate Customers

Load Factor	Average Monthly kW	Average Monthly kWh	Total Bill Using Rates 2/1/2010	Total Bill Using Rates 5/1/2010	Total Difference	% Total Difference
20%	5	730	$130.50	$126.50	($4.00)	(3.1%)
20%	10	1,460	$250.00	$242.00	($8.00)	(3.2%)
20%	15	2,190	$369.50	$357.50	($12.00)	(3.2%)
20%	25	3,650	$608.50	$588.50	($20.00)	(3.3%)
20%	50	7,300	$1,206.01	$1,166.00	($40.00)	(3.3%)
20%	75	10,950	$1,803.51	$1,743.50	($60.01)	(3.3%)
20%	100	14,600	$2,401.01	$2,321.01	($80.01)	(3.3%)
20%	150	21,900	$3,596.02	$3,476.01	($120.01)	(3.3%)
36%	5	1,314	$194.50	$187.30	($7.20)	(3.7%)
36%	10	2,628	$378.00	$363.60	($14.40)	(3.8%)
36%	15	3,942	$561.50	$539.90	($21.60)	(3.8%)
36%	25	6,570	$928.51	$892.50	($36.00)	(3.9%)
36%	50	13,140	$1,846.01	$1,774.01	($72.01)	(3.9%)
36%	75	19,710	$2,763.52	$2,655.51	($108.01)	(3.9%)
36%	100	26,280	$3,681.03	$3,537.01	($144.01)	(3.9%)
36%	150	39,420	$5,516.04	$5,300.02	($216.02)	(3.9%)
50%	5	1,825	$250.50	$240.50	($10.00)	(4.0%)
50%	10	3,650	$490.00	$470.00	($20.00)	(4.1%)
50%	15	5,475	$729.51	$699.50	($30.00)	(4.1%)
50%	25	9,125	$1,208.51	$1,158.50	($50.01)	(4.1%)
50%	50	18,250	$2,406.02	$2,306.01	($100.01)	(4.2%)
50%	75	27,375	$3,603.53	$3,453.51	($150.02)	(4.2%)
50%	100	36,500	$4,801.04	$4,601.02	($200.02)	(4.2%)
50%	150	54,750	$7,196.05	$6,896.02	($300.03)	(4.2%)

	Rates - Effective February 1, 2010	Rates - Proposed May 1, 2010	Difference
Customer Charge	**$11.00**	**$11.00**	**$0.00**
	All kW	All kW	All kW
Distribution Charge	$7.03	$7.03	$0.00
Stranded Cost Charge	$0.87	$0.87	$0.00
TOTAL	**$7.90**	**$7.90**	**$0.00**
	kWh	kWh	kWh
Distribution Charge	$0.00000	$0.00000	$0.00000
External Delivery Charge	$0.01425	$0.01425	$0.00000
Stranded Cost Charge	$0.00167	$0.00167	$0.00000
System Benefits Charge	$0.00330	$0.00330	$0.00000
Default Service Charge	$0.09037	$0.08489	($0.00548)
TOTAL	**$0.10959**	**$0.10411**	**($0.00548)**

Unitil Energy Systems, Inc.
Typical Bill Impacts - February 1, 2010 versus May 1, 2010
Impacts do NOT include the Electricity Consumption Tax
Impact on G2 kWh Meter Rate Customers

Average Monthly kWh	Total Bill Using Rates 2/1/2010	Total Bill Using Rates 5/1/2010	Total Difference	% Total Difference
15	$10.54	$10.46	($0.08)	(0.8%)
75	$19.10	$18.69	($0.41)	(2.2%)
150	$29.79	$28.97	($0.82)	(2.8%)
250	$44.06	$42.69	($1.37)	(3.1%)
350	$58.32	$56.40	($1.92)	(3.3%)
450	$72.58	$70.11	($2.47)	(3.4%)
550	$86.84	$83.83	($3.01)	(3.5%)
650	$101.10	$97.54	($3.56)	(3.5%)
750	$115.37	$111.26	($4.11)	(3.6%)
900	$136.76	$131.83	($4.93)	(3.6%)

	Rates - Effective February 1, 2010	Rates - Proposed May 1, 2010	Difference
kWh Meter Customer Charge	**$8.40**	**$8.40**	**$0.00**
	All kWh	**All kWh**	**All kWh**
Distribution Charge	$0.02975	$0.02975	$0.00000
External Delivery Charge	$0.01425	$0.01425	$0.00000
Stranded Cost Charge	$0.00495	$0.00495	$0.00000
System Benefits Charge	$0.00330	$0.00330	$0.00000
Default Service Charge	$0.09037	$0.08489	($0.00548)
TOTAL	**$0.14262**	**$0.13714**	**($0.00548)**

Unitil Energy Systems, Inc.
Typical Bill Impacts - February 1, 2010 versus May 1, 2010
Impacts do NOT include the Electricity Consumption Tax
Impact on G2 QRWH and SH Rate Customers

Average kWh	Total Bill Using Rates 2/1/2010	Total Bill Using Rates 5/1/2010	Total Difference	% Total Difference
100	$17.13	$16.58	($0.55)	(3.2%)
200	$30.50	$29.40	($1.10)	(3.6%)
300	$43.88	$42.23	($1.64)	(3.7%)
400	$57.25	$55.06	($2.19)	(3.8%)
500	$70.63	$67.89	($2.74)	(3.9%)
750	$104.06	$99.95	($4.11)	(3.9%)
1,000	$137.50	$132.02	($5.48)	(4.0%)
1,500	$204.38	$196.16	($8.22)	(4.0%)
2,000	$271.25	$260.29	($10.96)	(4.0%)
2,500	$338.13	$324.43	($13.70)	(4.1%)

	Rates - Effective February 1, 2010	Rates - Proposed May 1, 2010	Difference
Customer Charge	**$3.75**	**$3.75**	**$0.00**
	All kWh	All kWh	All kWh
Distribution Charge	$0.02088	$0.02088	$0.00000
External Delivery Charge	$0.01425	$0.01425	$0.00000
Stranded Cost Charge	$0.00495	$0.00495	$0.00000
System Benefits Charge	$0.00330	$0.00330	$0.00000
Default Service Charge	$0.09037	$0.08489	($0.00548)
TOTAL	**$0.13375**	**$0.12827**	**($0.00548)**

Unitil Energy Systems, Inc.
Typical Bill Impacts - February 1, 2010 versus May 1, 2010
Impacts do NOT include the Electricity Consumption Tax
Impact on G1 Rate Customers

Load Factor	Average Monthly kVa	Average Monthly kWh	Total Bill Using Rates 2/1/2010	Total Bill Using Rates 5/1/2010	Total Difference	% Total Difference
25.0%	200	36,500	$5,405.47	$4,768.18	($637.29)	(11.8%)
25.0%	400	73,000	$10,702.08	$9,427.50	($1,274.58)	(11.9%)
25.0%	600	109,500	$15,998.69	$14,086.82	($1,911.87)	(12.0%)
25.0%	800	146,000	$21,295.30	$18,746.14	($2,549.16)	(12.0%)
25.0%	1,000	182,500	$26,591.91	$23,405.46	($3,186.45)	(12.0%)
25.0%	1,500	273,750	$39,833.44	$35,053.76	($4,779.68)	(12.0%)
25.0%	2,000	365,000	$53,074.96	$46,702.06	($6,372.90)	(12.0%)
25.0%	2,500	456,250	$66,316.49	$58,350.36	($7,966.13)	(12.0%)
25.0%	3,000	547,500	$79,558.01	$69,998.66	($9,559.35)	(12.0%)
40.0%	200	58,400	$7,751.84	$6,732.17	($1,019.66)	(13.2%)
40.0%	400	116,800	$15,394.81	$13,355.48	($2,039.33)	(13.2%)
40.0%	600	175,200	$23,037.79	$19,978.80	($3,058.99)	(13.3%)
40.0%	800	233,600	$30,680.76	$26,602.11	($4,078.66)	(13.3%)
40.0%	1,000	292,000	$38,323.74	$33,225.42	($5,098.32)	(13.3%)
40.0%	1,500	438,000	$57,431.18	$49,783.70	($7,647.48)	(13.3%)
40.0%	2,000	584,000	$76,538.62	$66,341.98	($10,196.64)	(13.3%)
40.0%	2,500	730,000	$95,646.06	$82,900.26	($12,745.80)	(13.3%)
40.0%	3,000	876,000	$114,753.50	$99,458.54	($15,294.96)	(13.3%)
57.0%	200	83,220	$10,411.05	$8,958.03	($1,453.02)	(14.0%)
57.0%	400	166,440	$20,713.24	$17,807.20	($2,906.04)	(14.0%)
57.0%	600	249,660	$31,015.43	$26,656.37	($4,359.06)	(14.1%)
57.0%	800	332,880	$41,317.62	$35,505.54	($5,812.08)	(14.1%)
57.0%	1,000	416,100	$51,619.81	$44,354.71	($7,265.11)	(14.1%)
57.0%	1,500	624,150	$77,375.29	$66,477.63	($10,897.66)	(14.1%)
57.0%	2,000	832,200	$103,130.77	$88,600.56	($14,530.21)	(14.1%)
57.0%	2,500	1,040,250	$128,886.25	$110,723.48	($18,162.77)	(14.1%)
57.0%	3,000	1,248,300	$154,641.72	$132,846.40	($21,795.32)	(14.1%)
71.0%	200	103,660	$12,600.99	$10,791.09	($1,809.90)	(14.4%)
71.0%	400	207,320	$25,093.12	$21,473.32	($3,619.81)	(14.4%)
71.0%	600	310,980	$37,585.26	$32,155.55	($5,429.71)	(14.4%)
71.0%	800	414,640	$50,077.39	$42,837.78	($7,239.61)	(14.5%)
71.0%	1,000	518,300	$62,569.52	$53,520.00	($9,049.52)	(14.5%)
71.0%	1,500	777,450	$93,799.85	$80,225.58	($13,574.28)	(14.5%)
71.0%	2,000	1,036,600	$125,030.18	$106,931.15	($18,099.04)	(14.5%)
71.0%	2,500	1,295,750	$156,260.52	$133,636.72	($22,623.80)	(14.5%)
71.0%	3,000	1,554,900	$187,490.85	$160,342.29	($27,148.55)	(14.5%)

	Rates - Effective February 1, 2010	Rates - Proposed May 1, 2010	Difference
Customer Charge			
	$108.86	**$108.86**	**$0.00**
Distribution Charge	All kVA	All kVA	All kVA
Stranded Cost Charge	$5.69	$5.69	$0.00
TOTAL	$1.24	$1.24	$0.00
	$6.93	**$6.93**	**$0.00**
	All kWh	All kWh	All kWh
Distribution Charge	$0.00000	$0.00000	$0.00000
External Delivery Charge	$0.01425	$0.01425	$0.00000
Stranded Cost Charge	$0.00147	$0.00147	$0.00000
System Benefits Charge	$0.00330	$0.00330	$0.00000
Default Service Charge*	$0.08812	$0.07066	($0.01746)
TOTAL	**$0.10714**	**$0.08968**	**($0.01746)**

* Default Service Charges shown are based on the average of the DSC for each 3-month period.

Unitil Energy Systems, Inc.
Typical Bill Impacts - February 1, 2010 versus May 1, 2010
Impacts do NOT include the Electricity Consumption Tax
Impact on OL Rate Customers

	Nominal Watts	Lumens	Average Monthly kWh	Total Bill Using Rates 2/1/2010	Total Bill Using Rates 5/1/2010	Total Difference	% Total Difference
	Mercury Vapor:						
1	100	3,500	40	$12.39	$12.18	($0.22)	(1.8%)
2	175	7,000	67	$17.10	$16.74	($0.37)	(2.1%)
3	250	11,000	95	$21.67	$21.15	($0.52)	(2.4%)
4	400	20,000	154	$30.61	$29.77	($0.84)	(2.8%)
5	1,000	60,000	388	$71.08	$68.96	($2.13)	(3.0%)
6	250	11,000	95	$22.45	$21.93	($0.52)	(2.3%)
7	400	20,000	154	$31.62	$30.78	($0.84)	(2.7%)
8	1,000	60,000	388	$68.05	$65.93	($2.13)	(3.1%)
9	100	3,500	40	$12.47	$12.26	($0.22)	(1.8%)
10	175	7,000	67	$16.50	$16.14	($0.37)	(2.2%)
	High Pressure Sodium:						
11	50	4,000	21	$10.41	$10.30	($0.12)	(1.1%)
12	100	9,500	43	$14.03	$13.80	($0.24)	(1.7%)
13	150	16,000	60	$15.99	$15.66	($0.33)	(2.1%)
14	250	30,000	101	$23.22	$22.67	($0.55)	(2.4%)
15	400	50,000	161	$33.33	$32.45	($0.88)	(2.6%)
16	1,000	140,000	398	$71.86	$69.68	($2.18)	(3.0%)
17	150	16,000	60	$17.56	$17.23	($0.33)	(1.9%)
18	250	30,000	101	$24.30	$23.75	($0.55)	(2.3%)
19	400	50,000	161	$32.97	$32.09	($0.88)	(2.7%)
20	1,000	140,000	398	$72.10	$69.92	($2.18)	(3.0%)
21	50	4,000	21	$9.74	$9.63	($0.12)	(1.2%)
22	100	95,000	43	$13.24	$13.01	($0.24)	(1.8%)

	Rates - Effective February 1, 2010	Rates - Proposed May 1, 2010	Difference
Customer Charge	$0.00	$0.00	$0.00
	All kWh	All kWh	All kWh
Distribution Charge	$0.00000	$0.00000	$0.00000
External Delivery Charge	$0.01425	$0.01425	$0.00000
Stranded Cost Charge	$0.00495	$0.00495	$0.00000
System Benefits Charge	$0.00330	$0.00330	$0.00000
Default Service Charge	$0.09037	$0.08489	($0.00548)
TOTAL	$0.11287	$0.10739	($0.00548)

Luminaire Charges For Year Round Service:

	Mercury Vapor Rate/Mo.	Mercury Vapor Rate/Mo.	Mercury Vapor Rate/Mo.
1	$7.88	$7.88	$0.00
2	$9.54	$9.54	$0.00
3	$10.95	$10.95	$0.00
4	$13.23	$13.23	$0.00
5	$27.29	$27.29	$0.00
6	$11.73	$11.73	$0.00
7	$14.24	$14.24	$0.00
8	$24.26	$24.26	$0.00
9	$7.96	$7.96	$0.00
10	$8.94	$8.94	$0.00
	Sodium Vapor Rate/Mo.	Sodium Vapor Rate/Mo.	Sodium Vapor Rate/Mo.
11	$8.04	$8.04	$0.00
12	$9.18	$9.18	$0.00
13	$9.22	$9.22	$0.00
14	$11.82	$11.82	$0.00
15	$15.16	$15.16	$0.00
16	$26.94	$26.94	$0.00
17	$10.79	$10.79	$0.00
18	$12.90	$12.90	$0.00
19	$14.80	$14.80	$0.00
20	$27.18	$27.18	$0.00
21	$7.37	$7.37	$0.00
22	$8.39	$8.39	$0.00

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

DAVID L. CHONG

New Hampshire Public Utilities Commission
Docket No. DE 10-028

March 12, 2010

TABLE OF CONTENTS

LIST OF SCHEDULES

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David L. Chong. My business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. What is your position and what are your responsibilities?

A. I am Director of Finance for Unitil Service Corp., a subsidiary of Unitil Corporation that provides managerial, financial, regulatory and engineering services to Unitil Corporation's principal subsidiaries: Fitchburg Gas and Electric Light Company, Granite State Gas Transmission, Inc., Northern Utilities, Inc., and Unitil Energy Systems, Inc. ("UES" or the "Company"). In this capacity I am responsible for the management of treasury operations and banking relationships; planning and execution of financing programs; development, preparation and presentation of financial forecasts and plans; overseeing insurance programs; interfacing with the financial community and investors; and supporting the company's regulatory and ratemaking objectives.

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

A. Yes, I have previously presented testimony before this Commission in Docket Nos. DE 09-236 and DG 09-239.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I will discuss the development of the 2009 UES Default Service and Renewable Energy Credits Lead Lag Study ("2009 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' 2009 Default Service ("DS") and Renewable Energy Credits ("RECs") Lead Lag Study. The 2009 Study, presented in this filing as Schedule DC-1, is based upon data for the period January 1, 2009 through December 31, 2009 and calculates the net lag periods for G1 and Non-G1 customers to be 6.47 days and 9.40 days, respectively.

Q. Are the results of the 2009 Study included in the DS rates proposed in this filing?

A. Yes, the 2009 Study results are used to derive supply-related working capital costs included in DS rates beginning May 1, 2010, as described in the testimony of UES witness Linda S. McNamara.

IV. LEAD LAG STUDY METHODOLOGY

Q. How was the 2009 Study conducted?

A. The 2009 Study follows similar methodology (with a few exceptions described in the next Q&A) as in UES' 2008 Default Service and Renewable Energy Credits Lead Lag Study ("2008 Study") that was submitted in Docket No. DE 09-009. The 2009 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 2009 Study upon data for the twelve months ended December 31, 2009, and calculated net lag days separately for the G1 and Non-G1 customer classes.

Q. How does the methodology in the 2009 Study differ from the 2008 Study?

A. In UES' lead lag settlement letter dated July 16, 2009 under Docket No. DE 09-009, UES agreed to address the following four items in future lead lag studies, including the 2009 Study.

(i) UES will remove mailing time from the "meter reading to billing" calculation, and instead calculate "meter reading to recording of accounts receivable".

(ii) UES will reflect actual procurement experience for test year RECs, and use July 1 of the following year as the due date for any test year RECs that have not been procured.

(iii) In May 2009, UES changed its proposed Power Supply Agreement to reflect a monthly payment schedule, with a proposed payment date on the last business day of the following month. UES submits, however, that it is prudent to retain the flexibility to be able to negotiate a change in the language in any final supplier contract should a change result in a lower overall cost for customers. In future lead lag studies, UES will reflect actual test year payment experience related to DS contracts in effect for that test year.

(iv) UES will include the due date in its DS and REC expense lead calculations.

V. 2009 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 DC-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 2009 Study?

A. The 2009 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 DC-1, page 5 of 23.

Q. What is the lag period for the component "meter reading to recording of accounts receivable?"

A. The 2009 average "meter reading to recording of accounts receivable" lag is 1.15 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. The calculation of this lag component conforms to the settlement. See Schedule DC-1, pages 6 through 10 of 23.

Q. What is the lag period for the component "billing to collection?"

A. The 2009 average "billing to collection" lag is 24.11 days for G1 customers and 31.67 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 DC-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 2009 average "collection to receipt of available funds" lag is 1.35 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 DC-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 41.82 days for G1 customers and 49.38 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 DC-1, page 4, line 6.

Q. Please turn to the lead periods in the 2009 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. This calculation conforms to the settlement by including the payment date of the contract.

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 2009 Study, Schedule DC-2.

As of March 1, 2010, prior period adjustments made in 2010 related to 2009 were included in the calculation. Prior year adjustments made in 2009 that relate to 2008 were not included in the calculation. This methodology is similar to that used in George McCluskey's testimony dated 6-3-09 in Docket DE 09-009 and 010.

Q. In the settlement letter dated July 16, 2009, the Company modified its proposed Power Supply Agreement ("PSA") to reflect an end-of-month payment schedule. What was the outcome of this process?

A. As a result of the settlement, UES modifed the proposed PSA it issues with its DS RFP packages to provide for end-of-month payment terms. In the settlement, UES submitted that it is prudent to retain the flexibility to be able to negotiate a change in the language in any final supplier contract should such a change result in a lower overall cost for customers. During the solicitation process, UES works with suppliers to obtain the most favorable non-price terms each supplier is willing to offer, including payment terms. UES then accepts and evaluates final pricing in order to determine which offer provides the greatest overall value. As part of the evaluation process, UES factors the cost of interest expense associated with different payment terms.

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 2009 RECs, three assumptions were made to reflect actual payment activity towards the Company's 2009 REC commitment. First, the monthly cost of the RECs was assumed to be equivalent to the estimated costs of RECs included in rates in 2009. Second, actual payment activity as of March 1, 2010 towards the Company's 2009 REC commitment was applied in chronological order to the earliest month's estimated cost. Third, a payment date of July 1, 2010 was used for all remaining 2009 REC commitments, which is the last day to obtain 2009 RECs and/or make alternative compliance payments. The July 1, 2010 date conforms to the settlement related to RECs in the letter dated July 16, 2009. See Schedule DC-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 35.35 days, as shown on Schedule DC-1, page 20 of 23. The weighted days lead for Non-G1 customers is 39.98 days, as shown on Schedule DC-1, page 22 of 23.

Q. How is the total DS and REC lag determined?

A. For G1 customers, the DS and REC expense lead of 35.35 days is subtracted from the lag in receipt of revenue of 41.82 days to produce the total DS and REC lag of 6.47 days. For Non-G1 customers, the DS and REC expense lead of 39.98 days is subtracted from the lag in receipt of revenue of 49.38 days to produce the total DS and REC lag of 9.40 days. See Schedule DC-1, page 4 of 23.

Q. How do the results of the 2009 Study compare to the 2008 Study for G1 customers?

A. For G1 customers, the net lag in the 2009 Study of 6.47 days is 2.18 days higher than the net lag in the 2008 Study of 4.29 days. The increase in net lag was driven by a decrease in DS and REC expense lead of 3.71 days and offset by an overall revenue lag decrease of 1.53 days.

The revenue lag component, "meter reading to recording of accounts receivable" in the 2009 Study is 1.15 days compared to 3.16 days in the 2008 Study, a decrease of 2.01 days. As indicated earlier in my testimony, the Company adopted the methodology specified in the settlement to calculate "meter reading to recording of accounts receivable" versus the previous methodology used in the 2008 Study which calculated "meter reading to billing". All of the other components in revenue lag increased a total of 0.48 days in the 2009 Study compared to the 2008 Study. The combined change in all of the revenue lag components resulted in an overall revenue lag decrease of 1.53 days.

The DS and REC expense lead is 35.35 days in the 2009 Study compared to 39.06 days in the 2008 Study, a decrease of 3.71 days. The results of the 2009 Study and 2008 Study are not directly comparable because of variances in methodology. As mentioned above, the Company incorporated the settlement in its calculation of DS and REC expense leads by utilizing the due date of the payment and also by incorporating the alternative compliance payment date of July 1, 2010 for any RECs not yet acquired. This approach would have increased the DS and REC expense lead, so the overall net decrease in the expense lead is attributable to variances in actual payment history in the 2009 Study compared to the 2008 Study. For example, the DS average days lead in the 2009 Study is 28.10 days compared to 36.29 days in the 2008 Study. This decrease was not attributable to changes in payment terms, but rather largely due to prior period adjustments related to 2009 from a couple of the Company's suppliers.

Q. **How do the results of the 2009 Study compare to the 2008 Study for Non-G1 customers?**

A. For Non-G1 customers, the net lag in the 2009 Study of 9.40 days is 3.46 days lower than the net lag in the 2008 Study of 12.86 days. The decrease in net lag is attributable to a 0.96 day decrease in revenue lag and a 2.50 day increase in the DS and REC expense lead.

For the reasons given in the prior Q&A, the "meter reading to recording of accounts receivable" was 1.15 days in the 2009 Study, which is 2.01 days less than the "meter reading to billing" in the 2008 Study. "Billing to collection" was approximately 0.87 days higher and all other revenue lag components were approximately 0.18 days higher in the 2009 Study compared to the 2008 Study. The net effect of all of the changes in the revenue lag components resulted in a 0.96 decrease in the 2009 revenue lag compared to 2008.

The DS and REC expense lead is 2.50 days higher in 2009 compared to 2008. Part of this increase is attributable to the inclusion of the due date in the DS and REC payments as discussed in the prior Q&A. The remainder of the increase is largely attributable to the overall increase in the REC commitment from 2008 to 2009. In 2008, RECs represented 1.20% of total DS and REC expenses compared to 2.05% in 2009. The increased weighting of RECs coupled with the higher REC lead days contributes to the overall higher expense lead days in 2009 compared to 2008.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

UNITIL ENERGY SYSTEMS, INC.

DEFAULT SERVICE AND RENEWABLE ENERGY CREDITS

LEAD/LAG STUDY

FOR G1 AND NON-G1 CUSTOMERS

2009

Unitil Energy Systems, Inc.
Default Service Costs and Renewable Energy Credits Lead / Lag Study
For the Period January 1, 2009 Through December 31, 2009
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 lag period for DS and REC costs of **6.47 days for G1 Customers** and **9.40 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 2009, 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 1.15 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 24.11 days for G1 customers and 31.67 days for Non-G1 customers. See pages 11 and 12 of this Study.

D. <u>Collection to Receipt of Available Funds</u>
On average, 1.35 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 41.82 days for G1 customers and 49.38 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, 2009 Through December 31, 2009
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 35.35 days for G1 customers and 39.98 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 lag period of 6.47 days for G1 customers and 9.40 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 2009 Data

		G1 Customers		Non-G1 Customers	
Line No.	Descripton	Page Reference	Number of Days Delay	Page Reference	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	1.15 days	6 - 10	1.15 days
4	Billing to Collection	11	24.11 days	12	31.67 days
5	Collection to Receipt of Available Funds	13 - 19	1.35 days	13 - 19	1.35 days
6	Subtotal Revenue Lag Days		41.82 days		49.38 days
7	Less: Lead in Payment of Default Service Costs and Renewable Energy Credits	20	35.35 days	22	39.98 days
8	Total Default Service and Renewable Energy Credit Lag (Line 6 Less Line 7)		6.47 days		9.40 days

Receipt of Electric Service to Meter Reading
Average Days Delay

January 1, 2009 to December 31, 2009 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 2009	1.20
February 2009	1.10
March 2009	1.10
April 2009	1.32
May 2009	1.26
June 2009	1.13
July 2009	1.09
August 2009	1.21
September 2009	1.15
October 2009	1.06
November 2009	1.15
December 2009	1.06
Average	1.15

**Unitil Energy Systems, Inc.
Meter Reading to Recording of
Accounts Receivable
Monthly Detail**

January 2009

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Weighted Days Lag
1	61,846	86.29%	1	0.86
2	8,097	11.30%	2	0.23
3	954	1.33%	3	0.04
4	363	0.51%	4	0.02
5	120	0.17%	5	0.01
6	82	0.11%	6	0.01
7	67	0.09%	7	0.01
8-14	76	0.11%	11	0.01
Over 14	66	0.09%	14	0.01
Total	71,671	100.00%		1.20

February 2009

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Weighted Days Lag
1	66,880	93.33%	1	0.93
2	3,653	5.10%	2	0.10
3	602	0.84%	3	0.03
4	293	0.41%	4	0.02
5	53	0.07%	5	0.00
6	61	0.09%	6	0.01
7	37	0.05%	7	0.00
8 to 14	27	0.04%	11	0.00
Over 14	50	0.07%	14	0.01
Total	71,656	100.00%		1.10

March 2009

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	67,915	94.92%	1	0.95
2	1,777	2.48%	2	0.05
3	1,324	1.85%	3	0.06
4	184	0.26%	4	0.01
5	189	0.26%	5	0.01
6	45	0.06%	6	0.00
7	41	0.06%	7	0.00
8 to 14	47	0.07%	11	0.01
Over 14	25	0.03%	14	0.00
Total	71,547	100.00%		1.10

Unitil Energy Systems, Inc.
Meter Reading to Recording of
Accounts Receivable
Monthly Detail

April 2009

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	61,156	85.58%	1	0.86
2	3,791	5.30%	2	0.11
3	2,543	3.56%	3	0.11
4	3,137	4.39%	4	0.18
5	418	0.58%	5	0.03
6	289	0.40%	6	0.02
7	29	0.04%	7	0.00
8 to 14	58	0.08%	11	0.01
Over 14	40	0.06%	14	0.01
Total	71,461	100.00%		1.32

May 2009

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	57,980	80.97%	1	0.81
2	11,624	16.23%	2	0.32
3	1,249	1.74%	3	0.05
4	286	0.40%	4	0.02
5	104	0.15%	5	0.01
6	83	0.12%	6	0.01
7	26	0.04%	7	0.00
8 to 14	221	0.31%	11	0.03
Over 14	38	0.05%	14	0.01
Total	71,611	100.00%		1.26

June 2009

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	66,021	91.04%	1	0.91
2	5,155	7.11%	2	0.14
3	922	1.27%	3	0.04
4	208	0.29%	4	0.01
5	58	0.08%	5	0.00
6	60	0.08%	6	0.00
7	15	0.02%	7	0.00
8 to 14	50	0.07%	11	0.01
Over 14	27	0.04%	14	0.01
Total	72,516	100.00%		1.13

Unitil Energy Systems, Inc.
Meter Reading to Recording of
Accounts Receivable
Monthly Detail

July 2009

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	67,450	92.87%	1	0.93
2	4,494	6.19%	2	0.12
3	487	0.67%	3	0.02
4	81	0.11%	4	0.00
5	36	0.05%	5	0.00
6	15	0.02%	6	0.00
7	8	0.01%	7	0.00
8 to 14	28	0.04%	11	0.00
Over 14	27	0.04%	14	0.01
Total	72,626	100.00%		1.09

August 2009

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	60,365	83.10%	1	0.83
2	11,027	15.18%	2	0.30
3	756	1.04%	3	0.03
4	215	0.30%	4	0.01
5	117	0.16%	5	0.01
6	31	0.04%	6	0.00
7	31	0.04%	7	0.00
8 to 14	58	0.08%	11	0.01
Over 14	38	0.05%	14	0.01
Total	72,638	100.00%		1.21

September 2009

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	63,687	87.72%	1	0.88
2	7,981	10.99%	2	0.22
3	608	0.84%	3	0.03
4	131	0.18%	4	0.01
5	82	0.11%	5	0.01
6	28	0.04%	6	0.00
7	20	0.03%	7	0.00
8 to 14	25	0.03%	11	0.00
Over 14	40	0.06%	14	0.01
Total	72,602	100.00%		1.15

Unitil Energy Systems, Inc.
Meter Reading to Recording of
Accounts Receivable
Monthly Detail

October 2009

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	69,064	95.99%	1	0.96
2	2,233	3.10%	2	0.06
3	343	0.48%	3	0.01
4	130	0.18%	4	0.01
5	69	0.10%	5	0.00
6	22	0.03%	6	0.00
7	5	0.01%	7	0.00
8 to 14	46	0.06%	11	0.01
Over 14	36	0.05%	14	0.01
Total	71,948	100.00%		1.06

November 2009

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	63,119	88.25%	1	0.88
2	7,697	10.76%	2	0.22
3	400	0.56%	3	0.02
4	72	0.10%	4	0.00
5	61	0.09%	5	0.00
6	40	0.06%	6	0.00
7	30	0.04%	7	0.00
8 to 14	69	0.10%	11	0.01
Over 14	34	0.05%	14	0.01
Total	71,522	100.00%		1.15

December 2009

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	68,921	96.29%	1	0.96
2	2,183	3.05%	2	0.06
3	235	0.33%	3	0.01
4	91	0.13%	4	0.01
5	49	0.07%	5	0.00
6	31	0.04%	6	0.00
7	15	0.02%	7	0.00
8 to 14	26	0.04%	11	0.00
Over 14	25	0.03%	14	0.00
Total	71,576	100.00%		1.06

Unitil Energy Systems, Inc.
Number Of Days Lag In Billing To Collection
Twelve Months Average 1/09 - 12/09
G1 Customers

Month	Days in Month	Electric Sales Revenues	Daily Average (1/Days)	Accounts Receivable Electric Sales
		(1)	(2)	(3)
2009				
January	31	2,365,733	76,314	1,973,094
February	28	2,252,199	80,436	1,898,663
March	31	2,098,274	67,686	1,699,819
April	30	2,111,353	70,378	1,851,854
May	31	1,974,151	63,682	1,720,617
June	30	1,968,965	65,632	1,515,517
July	31	2,134,148	68,843	1,566,413
August	31	1,809,691	58,377	1,353,216
September	30	1,647,581	54,919	1,231,216
October	31	1,525,112	49,197	946,179
Novemeber	30	1,479,796	49,327	1,193,000
December	31	1,489,080	48,035	1,201,499
Total		22,856,083	752,827	18,151,087
Average		1,904,674	62,736	1,512,591
Payment Lag Days (3/2)				24.11

Unitil Energy Systems, Inc.
Number Of Days Lag In Billing To Collection
Twelve Months Average 1/09 - 12/09
Non-G1 Customers

Month	Days in Month	Electric Sales Revenues	Daily Average (1/Days)	Accounts Receivable Electric Sales
		(1)	(2)	(3)
2009				
January	31	13,667,338	440,882	13,745,425
February	28	12,423,993	443,714	13,372,424
March	31	11,412,533	368,146	12,049,490
April	30	11,068,234	368,941	11,940,153
May	31	9,466,606	305,374	10,465,020
June	30	8,999,810	299,994	9,794,970
July	31	10,075,212	325,007	9,466,217
August	31	10,935,076	352,744	10,882,917
September	30	10,233,205	341,107	10,435,212
October	31	8,649,415	279,013	8,565,717
Novemeber	30	8,632,072	287,736	9,139,123
December	31	9,674,169	312,070	10,771,500
Total		$ 125,237,664	$ 4,124,729	$ 130,628,168
Average		$ 10,436,472	$ 343,727	$ 10,885,681
Payment Lag Days (3/2)				31.67

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

2009	Percent of Funds: Available Same Day 0 Days Lag	Percent of Funds: 1 Day Float 1Day Lag	Percent of Funds: 2-Day Float 2 Days Lag	Percent of Funds: Total	Weighted Lag Days: 1 Day	Weighted Lag Days: 2 Days	Weighted Lag Days: Total
January	78%	17%	5%	100%	0.17	0.10	0.27
February	71%	21%	8%	100%	0.21	0.17	0.37
March	71%	20%	9%	100%	0.20	0.18	0.38
April	70%	22%	9%	100%	0.22	0.17	0.39
May	69%	24%	7%	100%	0.24	0.13	0.37
June	72%	22%	6%	100%	0.22	0.11	0.33
July	70%	23%	7%	100%	0.23	0.14	0.37
August	73%	22%	5%	100%	0.22	0.10	0.32
September	69%	25%	6%	100%	0.25	0.12	0.37
October	73%	22%	5%	100%	0.22	0.11	0.33
November	74%	22%	4%	100%	0.22	0.08	0.30
December	71%	23%	5%	100%	0.23	0.11	0.34

Average Weighted Lag Days for Availability of Funds 0.35 days

Summary

Total Lag Days from Receipt of Funds to Notification of Availability of F	1.00	day
Average Weighted Lag Days for Availability of Funds	0.35	days
Total Lag Days from Collection to Availability of Funds:	1.35	days

Unitil Energy Systems, Inc.
Remmitance Accounts

January, 2009	Available Balance	1 Day Float	2 Day Float	Total Available + Float
2	1,121,011	8,394	2,670	
5	1,415,058	2,395	275	
6	1,062,537	469,341	104,907	
7	1,078,584	315,136	59,534	
8	612,953	217,279	48,401	
9	784,855	12,476	35,925	
12	1,433,694	35,925	-	
13	1,170,339	220,691	64,397	
14	622,003	192,514	74,753	
15	472,487	209,972	44,392	
16	543,001	292,799	98,139	
20	2,314,085	23,515	74,624	
21	2,029,020	509,479	124,131	
22	947,988	289,400	132,265	
23	675,551	414,204	62,847	
26	1,588,321	103,144	77,221	
27	1,398,992	706,867	91,920	
28	1,309,448	301,458	89,897	
29	890,141	37,539	52,358	
30	201,281	336,471	82,020	
	21,671,348	4,698,999	1,320,676	27,691,023
% of Available Funds	78%	17%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.17	0.10	0.27

February, 2009	Available Balance	1 Day Float	2 Day Float	Total Available + Float
2	994,883	301,898	253,361	
3	1,867,156	60,886	192,475	
4	1,298,646	584,734	64,279	
5	895,747	317,270	179,695	
6	736,902	393,612	286,858	
9	1,728,181	126,134	160,724	
10	1,411,975	847,883	101,488	
11	1,319,856	275,179	105,898	
12	631,739	320,192	119,011	
13	686,706	238,076	130,221	
17	1,966,494	115,520	14,701	
18	2,039,419	443,208	88,248	
19	1,174,138	236,080	108,128	
20	697,094	265,410	137,059	
23	1,023,159	408,445	323,438	
24	1,587,049	168,145	254,738	
25	997,092	436,840	19,730	
26	661,688	363,930	15,374	
27	190,067	417,377	35,375	
	21,907,991	6,320,819	2,590,801	30,819,611
% of Available F	71%	21%	8%	100%
Float Days	0	1	2	
Weighted Float	-	0.21	0.17	0.37

Unitil Energy Systems, Inc.
Remmitance Accounts

March, 2009	Available Balance	1 Day Float	2 Day Float	Total Available + Float
2	1,574,174	15,203	20,172	
3	1,274,700	476,721	31,857	
4	1,031,755	314,445	75,942	
5	769,594	292,583	100,375	
6	763,061	296,689	249,504	
9	926,434	482,620	205,271	
10	1,801,340	119,284	85,987	
11	1,248,316	528,305	22,858	
12	824,967	208,169	188,959	
13	616,956	297,738	262,257	
16	992,482	538,054	171,409	
17	1,724,826	114,698	56,711	
18	1,039,640	209,391	10,273	
19	803,515	127,056	167,363	
20	734,738	237,339	210,172	
23	900,928	575,221	156,159	
24	1,524,761	134,789	102,772	
25	895,813	297,445	40,544	
26	687,733	192,046	121,282	
27	491,884	256,761	140,987	
30	777,252	447,813	238,132	
31	766,375	61,827	176,305	
	22,171,244	6,224,197	2,835,291	31,230,732
% of Available Funds	71%	20%	9%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.20	0.18	0.38

April, 2009	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	792,738	401,648	33,023	
2	688,008	191,938	82,180	
3	614,810	246,879	180,577	
6	1,305,057	59,610	120,967	
7	1,115,287	643,822	51,234	
8	1,082,514	258,959	61,547	
9	714,734	52,876	16,642	
10	547,253	249,780	159,976	
13	949,574	261,940	412,845	
14	1,152,085	256,631	310,513	
15	794,683	646,996	82,145	
16	903,952	209,466	14,564	
17	611,462	353,986	78,340	
20	1,040,792	248,976	205,955	
21	926,015	346,059	212,417	
22	719,310	328,015	93,225	
23	897,871	91,499	1,726	
24	775,782	255,841	9,993	
27	1,368,251	100,591	14,752	
28	1,187,134	184,988	81,613	
29	599,574	204,060	93,444	
30	132,731	270,521	22,345	
	18,919,620	5,865,081	2,340,023	27,124,724
% of Available Funds	70%	22%	9%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.22	0.17	0.39

Unitil Energy Systems, Inc.
Remmitance Accounts

May, 2009	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	1,039,121	6,518	15,827	
4	1,295,404	555,504	127,963	
5	1,826,031	29,619	98,344	
6	785,704	334,460	9,163	
7	709,366	202,763	93,186	
8	618,561	185,539	115,178	
11	860,661	1,036,442	192,181	
12	1,682,864	336,562	187,591	
13	596,007	393,202	55,198	
14	653,478	266,582	34,650	
15	677,179	178,287	57,967	
18	859,172	313,643	107,959	
19	1,044,932	534,021	80,557	
20	994,384	237,561	36,385	
21	580,038	196,546	108,625	
22	621,816	233,845	206,986	
26	1,100,241	357,777	133,790	
27	1,073,711	476,687	39,988	
28	840,614	232,374	8,517	
29	250,690	253,370	16,117	
	18,109,976	6,361,302	1,726,172	26,197,450
% of Available Funds	69%	24%	7%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.24	0.13	0.37

June, 2009	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	1,117,623	363,060	96,065	
2	1,395,657	424,164	91,744	
3	1,045,721	347,222	21,058	
4	835,932	189,977	24,793	
5	966,203	8,391	16,402	
8	879,920	548,272	170,641	
9	1,305,370	24,736	145,905	
10	425,932	339,788	9,790	
11	608,873	181,759	99,006	
12	644,307	236,370	131,729	
15	833,456	457,169	138,450	
16	1,268,232	190,425	86,140	
17	719,747	529,810	12,106	
18	874,966	179,922	100,199	
19	568,834	193,944	171,887	
22	1,302,103	101,147	70,740	
23	1,167,505	243,557	5,590	
24	538,741	153,079	4,426	
25	726,739	66,370	3,493	
26	587,122	264,341	16,711	
29	740,836	417,261	40,019	
30	408,950	350,856	26,483	
	18,962,770	5,811,620	1,483,377	26,257,767
% of Available Funds	72%	22%	6%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.22	0.11	0.33

Unitil Energy Systems, Inc.
Remmitance Accounts

July, 2009	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	944,652	387,380	61,712	
2	825,139	269,621	64,215	
3	579,499	234,929	26,618	
6	744,887	220,675	205,474	
7	1,045,058	102,755	102,719	
8	527,563	281,483	122,449	
9	508,203	249,868	128,047	
10	492,282	283,496	102,724	
13	735,276	211,106	71,629	
14	695,467	488,306	45,001	
15	827,590	192,206	61,499	
16	589,768	370,039	86,975	
17	1,262,543	32,370	54,605	
20	1,095,078	461,920	77,017	
21	1,226,429	19,759	57,258	
22	483,177	219,969	3,169	
23	493,029	229,986	9,969	
24	631,632	193,171	103,070	
27	813,414	427,017	122,884	
28	860,579	345,583	22,927	
29	650,241	167,376	41,166	
30	747,565	8,469	32,697	
31	332,748	301,865	57,303	
Total	17,111,818	5,699,349	1,661,127	24,472,294
% of Available Funds	70%	23%	7%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.23	0.14	0.37

August, 2009	Available Balance	1 Day Float	2 Day Float	Total Available + Float
3	1,046,834	434,736	92,174	
4	1,360,058	66,139	26,035	
5	685,731	239,823	1,961	
6	625,372	222,836	33,071	
7	585,737	236,677	76,229	
10	660,393	168,189	62,897	
11	1,081,915	126,324	49,801	
12	986,952	261,388	41,938	
13	587,579	267,717	54,865	
14	649,137	487,904	154,554	
17	1,153,770	299,020	129,884	
18	1,147,566	238,379	61,986	
19	877,849	236,770	54,636	
20	721,927	147,954	22,883	
21	782,159	109,182	53,188	
24	956,390	509,099	124,887	
25	1,192,074	365,453	90,533	
26	819,832	348,583	18,464	
27	875,378	108,782	13,558	
28	542,761	221,263	38,231	
31	600,096	221,887	60,982	
Total	17,939,512	5,318,105	1,262,757	24,520,374
% of Available Funds	73%	22%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.22	0.10	0.32

Unitil Energy Systems, Inc.
Remmitance Accounts

September, 2009	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	1,244,090	32,713	28,269	
2	652,781	328,359	6,551	
3	751,205	194,671	12,937	
4	698,161	352,805	23,522	
8	1,122,861	620,508	144,267	
9	1,251,705	245,530	121,674	
10	581,986	347,941	87,597	
11	864,173	269,274	109,277	
14	1,100,693	549,555	75,137	
15	1,347,409	228,047	29,077	
16	576,279	246,865	40,855	
17	592,637	185,272	94,983	
18	560,641	352,119	145,985	
21	1,069,004	487,222	137,516	
22	1,197,663	302,510	112,298	
23	623,591	282,020	74,982	
24	765,249	67,739	7,243	
25	679,358	171,038	46,067	
28	801,961	557,606	86,070	
29	1,229,287	372,924	86,083	
30	181,838	257,442	56,088	
	17,892,570	6,452,160	1,526,478	25,871,208
% of Available Funds	69%	25%	6%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.25	0.12	0.37

October, 2009	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	724,859	126,696	20,551	
2	587,332	358,780	87,580	
5	1,140,189	557,551	130,316	
6	1,574,812	82,498	47,818	
7	704,802	235,619	3,699	
8	604,527	253,946	57,532	
9	619,494	196,827	88,161	
13	927,185	643,096	121,105	
14	1,470,150	358,470	108,733	
15	731,670	352,103	41,921	
16	933,846	12,249	29,672	
19	967,757	369,343	78,110	
20	1,482,165	1,797	76,313	
21	817,795	233,882	45,625	
22	509,803	194,394	59,846	
23	524,986	216,259	71,349	
26	1,018,570	146,691	84,954	
27	871,872	269,995	18,251	
28	622,898	175,167	36,505	
29	599,802	324,051	60,269	
30	110,546	206,224	61,183	
	17,545,060	5,315,638	1,329,493	24,190,191
% of Available Funds	73%	22%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.22	0.11	0.33

Unitil Energy Systems, Inc.
Remmitance Accounts

November, 2009	Available Balance	1 Day Float	2 Day Float	Total Available + Float
2	1,023,503	276,000	39,935	
3	1,145,042	297,893	50,802	
4	693,331	220,606	40,410	
5	559,876	225,455	31,958	
6	856,416	5,657	26,301	
9	785,225	339,734	7,101	
10	900,001	416,498	76,946	
12	953,663	145,913	89,887	
13	562,809	270,170	31,647	
16	944,812	365,245	30,860	
17	1,018,496	36,544	11,615	
18	310,021	79,260	1,381	
19	476,550	562,446	104,271	
20	1,004,462	155,846	124,188	
23	636,699	429,518	29,065	
24	1,103,318	134,772	34,820	
25	802,510	170,777	29,642	
27	572,829	27,287	2,355	
30	811,040	296,420	58,524	
	15,160,603	4,456,041	821,708	20,438,352
% of Available Funds	74%	22%	4%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.22	0.08	0.30

December, 2009	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	1,413,321	3,640	54,884	
2	588,000	239,349	71,982	
3	589,240	745	71,237	
4	393,150	544,086	89,118	
7	1,049,452	14,164	83,030	
8	332,125	83,671	1,108	
9	239,791	9,709	3,412	
10	218,028	119,646	23,709	
11	888,318	76,393	48,815	
14	1,349,246	867,145	125,810	
15	1,720,305	298,120	96,190	
16	659,150	305,254	41,697	
17	569,993	196,889	13,499	
18	474,216	52,579	6,962	
21	686,613	409,019	91,718	
22	978,697	31,009	102,665	
23	195,049	270,677	28,315	
24	515,997	222,592	33,964	
28	645,971	473,735	47,347	
29	849,216	126,265	56,126	
30	624,585	333,795	54,428	
31	200,948	309,838	14,867	
	15,181,410	4,988,320	1,160,883	21,330,613
% of Available Funds	71%	23%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.23	0.11	0.34

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 DC-2	$ 7,516,296	97.67%	28.10 days	27.45 days
G1 Renewable Energy Credits	21	$ 179,123	2.33%	339.48 days	7.90 days
Total		$ 7,695,419	100.00%		35.35 days

UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF RENEWABLE ENERGY CREDITS

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	2009												
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
RECs*													
Period Begin	1/1/2009	2/1/2009	3/1/2009	4/1/2009	5/1/2009	6/1/2009	7/1/2009	8/1/2009	9/1/2009	10/1/2009	11/1/2009	12/1/2009	
Period End	1/31/2009	2/28/2009	3/31/2009	4/30/2009	5/31/2009	6/30/2009	7/31/2009	8/31/2009	9/30/2009	10/31/2009	11/30/2009	12/31/2009	
$ Amount	$0	$2,799	$15,422	$14,522	$13,115	$13,213	$14,909	$16,624	$16,992	$16,896	$13,836	$14,198	$152,526
% to Total	0.00%	1.56%	8.61%	8.11%	7.32%	7.38%	8.32%	9.28%	9.49%	9.43%	7.72%	7.93%	85.15%
Payment Date**	7/1/2010	7/1/2010	7/1/2010	7/1/2010	7/1/2010	7/1/2010	7/1/2010	7/1/2010	7/1/2010	7/1/2010	7/1/2010	7/1/2010	
Lead Period	531.50	502.00	472.50	442.00	411.50	381.00	350.50	319.50	289.00	258.50	228.00	197.50	
Weighted Days	-	7.84	40.68	35.83	30.13	28.10	29.17	29.65	27.41	24.38	17.61	15.66	286.46 days
REC Purchases***													
Period Begin	1/1/2009	1/1/2009	2/1/2009	2/1/2009	2/1/2009								
Period End	1/31/2009	1/31/2009	2/28/2009	2/28/2009	2/28/2009								
$ Amount	$11,093	$3,257	$4,016	$1,498	$6,734								$26,597
% to Total	6.19%	1.82%	2.24%	0.84%	3.76%								14.85%
Payment Date	12/30/2009	1/15/2010	1/15/2010	2/9/2010	3/1/2010								
Lead Period	348.50	364.50	335.00	360.00	380.00								
Weighted Days	21.58	6.63	7.51	3.01	14.29								53.02 days
Total $ Amount	$11,093	$6,056	$19,438	$16,020	$19,848	$13,213	$14,909	$16,624	$16,992	$16,896	$13,836	$14,198	$179,123
Weighted Days													339.48 days

* Estimated cost of RECs included in rates in 2009.
** The last day to acquire 2009 Renewable Energy Credits and/or make alternative compliance payments is July 1, 2010.
*** Actual purchasing activity for 2009 RECs applied in chronological order to monthly budgeted amounts.

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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 DC-2	$ 74,063,710	97.95%	33.48 days	32.79 days
Non-G1 Renewable Energy Credits	23	$ 1,548,923	2.05%	351.05 days	7.19 days
Total		$ 75,612,633	100.00%		39.98 days

UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF RENEWABLE ENERGY CREDITS

NON-G1	2009												
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
RECs*													
Period Begin	1/1/2009	2/1/2009	3/1/2009	4/1/2009	5/1/2009	6/1/2009	7/1/2009	8/1/2009	9/1/2009	10/1/2009	11/1/2009	12/1/2009	
Period End	1/31/2009	2/28/2009	3/31/2009	4/30/2009	5/31/2009	6/30/2009	7/31/2009	8/31/2009	9/30/2009	10/31/2009	11/30/2009	12/31/2009	
$ Amount	$0	$91,918	$150,691	$126,922	$115,490	$107,927	$110,251	$133,196	$143,918	$126,108	$114,642	$116,702	$1,337,763
% to Total	0.00%	5.93%	9.73%	8.19%	7.46%	6.97%	7.12%	8.60%	9.29%	8.14%	7.40%	7.53%	86.37%
Payment Date**	7/1/2010	7/1/2010	7/1/2010	7/1/2010	7/1/2010	7/1/2010	7/1/2010	7/1/2010	7/1/2010	7/1/2010	7/1/2010	7/1/2010	
Lead Period	531.50	502.00	472.50	442.00	411.50	381.00	350.50	319.50	289.00	258.50	228.00	197.50	
Weighted Days	-	29.79	45.97	36.22	30.68	26.55	24.95	27.47	26.85	21.05	16.88	14.88	301.29 days
REC Purchases***													
Period Begin	1/1/2009	1/1/2009	1/1/2009	1/1/2009	2/1/2009								
Period End	1/31/2009	1/31/2009	1/31/2009	1/31/2009	2/28/2009								
$ Amount	$82,764	$60,227	$12,402	$8,538	$47,228								$211,160
% to Total	5.34%	3.89%	0.80%	0.55%	3.05%								13.63%
Payment Date	12/30/2009	1/15/2010	2/9/2010	3/1/2010	3/1/2010								
Lead Period	348.50	364.50	389.50	409.50	380.00								
Weighted Days	18.62	14.17	3.12	2.26	11.59								49.76 days
Total $ Amount	$82,764	$152,145	$163,093	$135,460	$162,718	$107,927	$110,251	$133,196	$143,918	$126,108	$114,642	$116,702	$1,548,923
Weighted Days													351.05 days

* Estimated cost of RECs included in rates in 2009.
** The last day to acquire 2009 Renewable Energy Credits and/or make alternative compliance payments is July 1, 2010.
*** Actual purchasing activity for 2009 RECs applied in chronological order to monthly budgeted amounts.

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UNITIL ENERGY SYSTEMS, INC.

REDACTED WORKPAPERS

FOR THE

DEFAULT SERVICE AND RENEWABLE ENERGY CREDITS

LEAD/LAG STUDY

FOR G1 AND NON-G1 CUSTOMERS

2009

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	$ 7,516,296	97.67%	28.10 days	27.45 days
G1 Renewable Energy Credits	Schedule DC-1 p 21	$ 179,123	2.33%	339.48 days	7.90 days
Total		$ 7,695,419	100.00%		35.35 days
Detail for G1 Default Service Supplier Costs					
Supplier A	3	$ 1,233,181	16.41%	REDACTED	REDACTED
Supplier B	4	$ 5,502,677	73.21%	REDACTED	REDACTED
Supplier C	5	$ 780,438	10.38%	REDACTED	REDACTED
Total G1 Default Service Supplier Costs		$ 7,516,296	100.00%		28.10 days

REDACTED
UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF ELECTRIC COSTS

DS SERVICE POWER SUPPLY CONTRACTS

G1	MONTH ENERGY PURCHASES DELIVERED												
	2009												
SUPPLIERS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Supplier A													
Normal Service													
Period Begin								8/1/2009	9/1/2009	10/1/2009			
Period End								8/31/2009	9/30/2009	10/31/2009			
$ Amount								$470,965	$389,697	$403,701			$1,264,363
% to Total								38.19%	31.60%	32.74%			102.53%
Payment Date								REDACTED	REDACTED	REDACTED			
Lead Period								REDACTED	REDACTED	REDACTED			
Weighted Days								REDACTED	REDACTED	REDACTED			REDACTED
Prior Period Adjustments (shown in billing period in 2009)													
Period Begin								8/1/2009					
Period End								8/31/2009					
$ Amount								-$31,181					-$31,181
% to Total								-2.53%					-2.53%
Payment Date								REDACTED					
Lead Period								REDACTED					
Weighted Days								REDACTED					REDACTED
Total $ Amount	$0	$0	$0	$0	$0	$0	$0	$439,783	$389,697	$403,701	$0	$0	$1,233,181
Weighted Days													REDACTED

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REDACTED
UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF ELECTRIC COSTS

DS SERVICE POWER SUPPLY CONTRACTS

G1	MONTH ENERGY PURCHASES DELIVERED												
	2009												
SUPPLIERS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Supplier B													
Normal Service													
Period Begin	1/1/2009	2/1/2009	3/1/2009	4/1/2009	5/1/2009	6/1/2009	7/1/2009						
Period End	1/31/2009	2/28/2009	3/31/2009	4/30/2009	5/31/2009	6/30/2009	7/31/2009						
$ Amount	$1,323,715	$918,073	$859,104	$813,722	$627,741	$663,757	$735,204						$5,941,317
% to Total	24.06%	16.68%	15.61%	14.79%	11.41%	12.06%	13.36%						107.97%
Payment Date	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED						
Lead Period	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED						
Weighted Days	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED						REDACTED
Prior Period Adjustments													
(shown in billing period in 2009)													
Period Begin	1/1/2009	2/1/2009	3/1/2009	4/1/2009	5/1/2009	6/1/2009	7/1/2009						
Period End	1/31/2009	2/28/2009	3/31/2009	4/30/2009	5/31/2009	6/30/2009	7/31/2009						
$ Amount	-$260,768	-$32,035	-$57,241	-$29,230	-$17,856	-$12,096	-$29,414						-$438,639
% to Total	-4.74%	-0.58%	-1.04%	-0.53%	-0.32%	-0.22%	-0.53%						-7.97%
Payment Date	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED						
Lead Period	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED						
Weighted Days	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED						REDACTED
Total $ Amount	$1,062,947	$886,039	$801,863	$784,492	$609,885	$651,661	$705,791						$5,502,677

Weighted Days REDACTED

REDACTED
UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF ELECTRIC COSTS

DS SERVICE POWER SUPPLY CONTRACTS

G1	MONTH ENERGY PURCHASES DELIVERED												
	2009												
SUPPLIERS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Supplier C													
Normal Service													
Period Begin											11/1/2009	12/1/2009	
Period End											11/30/2009	12/31/2009	
$ Amount											$364,305	$416,132	$780,438
% to Total											46.68%	53.32%	100.00%
Payment Date											REDACTED	REDACTED	
Lead Period											REDACTED	REDACTED	
Weighted Days											REDACTED	REDACTED	REDACTED
Prior Period Adjustments (shown in billing period in 2009)													
Period Begin													
Period End													
$ Amount													$0
% to Total													0.00%
Payment Date													
Lead Period													
Weighted Days													REDACTED
Total $ Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$364,305	$416,132	$780,438
Weighted Days													REDACTED

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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	$ 74,063,710	97.95%	33.48 days	32.79 days
Renewable Energy Credits	Schedule DC-1 p 23	$ 1,548,923	2.05%	351.05 days	7.19 days
Total		$ 75,612,633	100.00%		39.98 days
Detail for Non-G1 Default Service Supplier Costs					
Supplier D	7	$ 37,236,907	50.28%	REDACTED	REDACTED
Supplier E	8	$ 16,185,553	21.85%	REDACTED	REDACTED
Supplier F	9	$ 20,641,251	27.87%	REDACTED	REDACTED
Total Non-G1 Default Service Supplier Costs		$ 74,063,710	100.00%		33.48 days

REDACTED
UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF ELECTRIC COSTS

DS SERVICE POWER SUPPLY CONTRACTS

NON-G1 SUPPLIERS	2009 JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Supplier D													
Normal Service													
Period Begin	1/1/2009	2/1/2009	3/1/2009	4/1/2009	5/1/2009	6/1/2009	7/1/2009	8/1/2009	9/1/2009	10/1/2009	11/1/2009	12/1/2009	
Period End	1/31/2009	2/28/2009	3/31/2009	4/30/2009	5/31/2009	6/30/2009	7/31/2009	8/31/2009	9/30/2009	10/31/2009	11/30/2009	12/31/2009	
$ Amount	$4,552,641	$3,817,547	$3,356,253	$2,716,932	$2,741,484	$2,899,650	$3,592,266	$4,225,040	$2,708,635	$2,803,169	$1,464,158	$1,976,682	$36,854,458
% to Total	12.23%	10.25%	9.01%	7.30%	7.36%	7.79%	9.65%	11.35%	7.27%	7.53%	3.93%	5.31%	98.97%
Payment Date	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	
Lead Period	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	
Weighted Days	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Prior Period Adjustments (shown in billing period in 2009)													
Period Begin	1/1/2009	2/1/2009	3/1/2009	4/1/2009	5/1/2009	6/1/2009	7/1/2009	8/1/2009	9/1/2009				
Period End	1/31/2009	2/28/2009	3/31/2009	4/30/2009	5/31/2009	6/30/2009	7/31/2009	8/31/2009	9/30/2009				
$ Amount	$69,422	$50,337	$74,731	$44,176	($329)	$20,621	$43,419	$50,196	$29,876				$382,449
% to Total	0.19%	0.14%	0.20%	0.12%	0.00%	0.06%	0.12%	0.13%	0.08%				1.03%
Payment Date	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED				
Lead Period	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED				
Weighted Days	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED				REDACTED
Total $ Amount	$4,622,062	$3,867,884	$3,430,984	$2,761,108	$2,741,156	$2,920,271	$3,635,685	$4,275,236	$2,738,511	$2,803,169	$1,464,158	$1,976,682	$37,236,907
Weighted Days													REDACTED

REDACTED
UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF ELECTRIC COSTS

DS SERVICE POWER SUPPLY CONTRACTS

NON-G1	2009												
SUPPLIERS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Supplier E													
Normal Service													
Period Begin	1/1/2009	2/1/2009	3/1/2009	4/1/2009									
Period End	1/31/2009	2/28/2009	3/31/2009	4/30/2009									
$ Amount	$5,051,798	$4,214,965	$3,731,879	$2,923,669									$15,922,310
% to Total	31.21%	26.04%	23.06%	18.06%									98.37%
Payment Date	REDACTED	REDACTED	REDACTED	REDACTED									
Lead Period	REDACTED	REDACTED	REDACTED	REDACTED									
Weighted Days	REDACTED	REDACTED	REDACTED	REDACTED									REDACTED
Prior Period Adjustments (shown in billing period in 2009)													
Period Begin	1/1/2009	2/1/2009	3/1/2009	4/1/2009									
Period End	1/31/2009	2/28/2009	3/31/2009	4/30/2009									
$ Amount	$77,033	$55,577	$83,095	$47,537									$263,243
% to Total	0.48%	0.34%	0.51%	0.29%									1.63%
Payment Date	REDACTED	REDACTED	REDACTED	REDACTED									
Lead Period	REDACTED	REDACTED	REDACTED	REDACTED									
Weighted Days	REDACTED	REDACTED	REDACTED	REDACTED									REDACTED
Total $ Amount	$5,128,831	$4,270,542	$3,814,973	$2,971,206	$0	$0	$0	$0	$0	$0	$0	$0	$16,185,553
Weighted Days													REDACTED

REDACTED
UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF ELECTRIC COSTS

DS SERVICE POWER SUPPLY CONTRACTS

NON-G1	2009												
SUPPLIERS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Supplier F													
Normal Service - 1st Period													
Period Begin					5/1/2009	6/1/2009	7/1/2009	8/1/2009	9/1/2009	10/1/2009	11/1/2009	12/1/2009	
Period End					5/15/2009	6/15/2009	7/15/2009	8/15/2009	9/15/2009	10/15/2009	11/15/2009	12/15/2009	
$ Amount					$905,039	$991,089	$1,073,059	$1,338,452	$980,235	$950,734	$1,500,349	$1,967,582	$9,706,539
% to Total					4.38%	4.80%	5.20%	6.48%	4.75%	4.61%	7.27%	9.53%	47.02%
Payment Date					REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	
Lead Period					REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	
Weighted Days					REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Normal Service - 2nd Period													
Period Begin					5/16/2009	6/16/2009	7/16/2009	8/16/2009	9/16/2009	10/16/2009	11/16/2009	12/16/2009	
Period End					5/31/2009	6/30/2009	7/31/2009	8/31/2009	9/30/2009	10/31/2009	11/30/2009	12/31/2009	
$ Amount					$989,197	$1,051,210	$1,353,503	$1,545,946	$952,864	$1,044,211	$1,517,993	$2,380,571	$10,835,496
% to Total					4.79%	5.09%	6.56%	7.49%	4.62%	5.06%	7.35%	11.53%	52.49%
Payment Date					REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	
Lead Period					REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	
Weighted Days					REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Prior Period Adjustments (shown in billing period in 2009)													
Period Begin					5/1/2009	6/1/2009	7/1/2009	8/1/2009	9/1/2009				
Period End					5/31/2009	6/30/2009	7/31/2009	8/31/2009	9/30/2009				
$ Amount					($227)	$14,524	$29,329	$34,268	$21,322				$99,216
% to Total					0.00%	0.07%	0.14%	0.17%	0.10%				0.48%
Payment Date					REDACTED	REDACTED	REDACTED	REDACTED	REDACTED				
Lead Period					REDACTED	REDACTED	REDACTED	REDACTED	REDACTED				
Weighted Days					REDACTED	REDACTED	REDACTED	REDACTED	REDACTED				REDACTED
Total $ Amount	$0	$0	$0	$0	$1,894,009	$2,056,824	$2,455,891	$2,918,666	$1,954,421	$1,994,945	$3,018,342	$4,348,153	$20,641,251
Weighted Days													REDACTED