UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

TODD M. BOHAN

New Hampshire Public Utilities Commission

Docket No.: DE 14-

June 17, 2014

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Todd M. Bohan. My business address is 6 Liberty Lane West, Hampton, NH.

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

A. I am employed by Unitil Service Corp. (”USC”) as a Senior Energy Analyst. USC provides management and administrative services to Unitil Energy Systems, Inc. (“UES”) and Unitil Power Corp. (“UPC”).

Q. Please describe your relevant educational and work experience.

A. I graduated *magna cum laude* from Saint Anselm College, Manchester, New Hampshire in 1987 with a Bachelor of Arts degree in Financial Economics. I earned a Masters in Economics from Clark University, Worcester, Massachusetts in May 1990. In September 1995, I earned a Ph.D. in Economics from Clark University. Before joining Unitil, I worked for Bay State Gas Company as a Rate Analyst. Prior to working for Bay State, I was employed as a Utility Analyst and an Economist in the Economics Department of the New Hampshire Public Utilities Commission. I joined Unitil Service Corp. in November 1998, and have been involved in various regulatory proceedings. In August of 2010, I joined the Energy Contracts group and have primary responsibilities in the areas of electric market operation and data reporting, default service administration and budgeting, and competitive electric supplier operations.

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

A. Yes. I have testified before the Commission on various regulatory matters, most recently in UES's Default Service Solicitation proceeding, Docket No. DE 14-061 and UES's Stranded Cost Recovery and External Delivery Charge Reconciliation and Rate Filing, Docket No. DE 13-172.

II. SUMMARY OF TESTIMONY

Q. Please summarize your testimony in this proceeding.

A. My testimony presents the cost data and explains the reasons for the proposed changes to UES's Stranded Cost Charge ("SCC"), and External Delivery Charge ("EDC"), effective August 1, 2014. Ms. Linda S. McNamara presents the reconciliation for the SCC and EDC through July 2014 and the rate development for the SCC and EDC for the period beginning August 1, 2014 and ending July 31, 2015, based on the cost data included in my testimony.

III. STRANDED COST CHARGE COSTS

Q. What costs are included in the SCC?

A. The SCC includes the Contract Release Payments ("CRP") from Unitil Power Corp., charged in accordance with the Amended Unitil System Agreement, approved by both the Commission in Docket No. DE 01-247 and by the FERC.

Schedule TMB-1, page 1, provides a description of the CRP. Page 2 provides the CRP by month reflecting actual data from August 2012 through April 2014 and estimated data from May 2014 through July 2015. These include costs associated with the recovery of a customer billing adjustment as approved in docket DE 11-105 and as discussed in the testimony of Ms. McNamara.

Q. Please describe the Amended Unitil System Agreement.

A. The purpose of the Amended Unitil System Agreement was to restructure UES's power supply in order to implement retail choice. Prior to the implementation of the Amended Unitil System Agreement on May 1, 2003, UES purchased full-requirements power supply from UPC at fully reconciling, cost-of-service rates.

The Amended Unitil System Agreement provides for termination of power sales from UPC to UES and the payment of UPC's on-going costs by UES. These on-going costs are defined in the Amended Unitil System Agreement as either CRP or Administrative Service Charges ("ASC"). UES recovers the CRP through the SCC and the ASC through the EDC. The ASC will be discussed later under the EDC costs.

Q. Please describe the CRP.

A. The CRP is calculated in accordance with Appendix 1 of the Amended Unitil System Agreement. The CRP is equal to the sum of the Portfolio Sales Charge, the Residual Contract Obligations, the Hydro-Quebec Support Payments, and True-Ups from Prior Periods.

The Portfolio Sales Charge and the Residual Contract Obligations have ended. The CRP estimates in this filing include no Portfolio Sales Charge and no Residual Contract Obligations. UPC's last Portfolio Sales Charge payment under the Mirant Agreement was made in October 2010, and UPC's last Residual Contract Obligation buyout payment (Indeck contract buyout) was made in September 2009.

The Hydro-Quebec Phase II Agreements require UPC to support the Hydro-Quebec Phase II facilities through October 2020. These facilities are part of one high-voltage, direct-current ("HVDC") interconnection between New England and Quebec. UPC has no obligation to support Phase I of these facilities. Currently, the costs for maintenance and construction of these facilities are paid by Interconnection Rights Holders ("IRH") through support agreements between the IRH members and the owners of the HVDC transmission facilities. The Hydro-Quebec Support Payments include all costs incurred by UPC pursuant to the Hydro-Quebec Phase II Agreements, offset by any revenues received by UPC for sales of UPC's Hydro-Quebec Phase II entitlement. The Hydro-Quebec Support Payments are not a known payment stream because they are based on the cost-of-service of the Hydro-Quebec Phase II transmission facilities. As discussed below, UPC receives revenue for short-term sales of transmission rights and capacity rights. These revenues operate to offset the expense of the Hydro-Quebec Support Payments.

The True-ups from Prior Periods reflect any differences in costs resulting from the reconciliation of estimated costs to actual costs under the CRP component of the Amended Unitil System Agreement. The True-ups from Prior Periods also provide for the reconciliation of costs billed to UPC for services purchased in UPC's performance of the Unitil System Agreement, prior to May 1, 2003. The CRP estimates in the current filing reflect no True-ups from Prior Periods.

Q. Please provide an estimate of each of the components of the CRP.

A. Details regarding the CRP are provided in Schedule TMB-3. This shows the actual itemized CRP and ASC charges as billed by UPC to UES for the period beginning August 2012 through April 2014 under the Amended Unitil System Agreement. Beginning on page 2 of Schedule TMB-3, estimated CRP and ASC for the 15-month period beginning May 2014 and ending July 2015 are presented. UPC bills UES on estimated data, prior to the beginning of the month of service. These estimates are trued-up to actuals on a two-month lag.

Q. Please provide a comparison of the estimated CRP for the upcoming SCC rate period (August 2014 through July 2015) to the projected CRP for the current SCC rate period (August 2013 through July 2014).

A. Table 1 below provides a comparison of the estimated CRP for the upcoming SCC rate period (August 2014 through July 2015) to the projected actual CRP for the current SCC rate period (August 2013 through July 2014).

Table 1. Comparison of Estimated CRP for August 2014 through July 2015 to Projected CRP for August 2013 through July 2014
Unitil Power Corp.

Line No.	Line Item Description	Aug 2013 - July 2014 9 Months Act. and 3 Months Est.	Aug 2014 - July 2015 Estimate	Variance (Aug 2014 - July 2015 Costs minus Aug 2013 - July 2014 Costs)
1.	Portfolio Sales Charge	$0	$0	$0
2.	Residual Contract Obligations	$0	$0	$0
3.	Hydro-Quebec Support Payments	$181,228	$181,860	$632
4.	Subtotal (L. 2 through 4)	$181,228	$181,860	$632
5.	True-up for estimate	($6,971)	$0	$6,971
6.	Obligations prior to May 1, 2003	$0	$0	$0
7.	Total Contract Release Payments as billed by Unitil Power Corp.	$174,257	$181,860	$7,603

At the time of the preparation of this estimate of the CRP, actual CRP expense data was available through April 2014. As such, the projected actual CRP for the current SCC rate period (August 2013 through July 2014) presented in Table 1 is comprised of nine months of actual data and three months of estimated data.

Q. Please report on the efforts by UPC to mitigate the stranded cost associated with the Hydro-Quebec Phase II Agreements.

A. UPC mitigates these costs through short-term sales of the transmission rights and capacity, which UPC is entitled to through its support of the Hydro-Quebec Phase II facilities. Currently, UPC resells its transmission rights on a short-term basis through a brokering agreement with Central Vermont Public Service Corporation ("CVPS"). Under this brokering agreement, CVPS offers UPC's transmission rights associated with the Hydro-Quebec Phase II facilities for sale on a short-term basis through the CVPS' OASIS website. CVPS has authority under this agreement to enter into binding sales of UPC's Hydro-Quebec transmission rights for transactions of one month or less in duration. UPC also has rights to Hydro-Quebec Interconnection Capability Credit ("HQICC"), pursuant to the ISO Tariff. UPC is reimbursed by CVPS for its HQICC at a price equal to the ISO Net Regional Clearing Price.[1] Please refer to Schedule TMB-5 for itemized cost and revenue offsets, related to the Hydro-Quebec Phase II Support Agreements.

IV. EXTERNAL DELIVERY CHARGE COSTS

Q. What costs are included in the EDC?

A. Schedule TMB-2, page 1 provides a description of the costs included in the EDC:

1) Third Party Transmission Providers (NU Network Integration Transmission Service);
2) Regional Transmission and Operating Entities;
3) Third Party Transmission Providers (NU Wholesale Distribution);
4) Transmission-Based Assessments and Fees;
5) Load Estimation and Reporting System Costs;
6) Data and Information Services;
7) Legal Charges;
8) Consulting Outside Service Charges;
9) Administrative Service Charges;
10) Non-Distribution Portion of the Annual PUC Assessment;
11) Working Capital Associated with Other Flow-Through Operating Expenses;
12) Regional Greenhouse Gas Initiative Rebates; and
13) Lost Distribution Revenue from Net Metering Generation.

Items 1), 2), and 3) of the Schedule are discussed below:

The Third Party Transmission Providers (NU Network Integration Transmission Service) component of the EDC consists of Network Integration Transmission

[1] The Net Regional Clearing Price is calculated by first adding Forward Capacity Auction payments to Net Reconfiguration Auction Credits or Charges and subtracting Peak Energy Rent Adjustments. This total is then divided by the Net Regional Supply Obligation.

Service taken by UES and provided by the Northeast Utilities Companies ("NU") pursuant to Schedule 21-NU of the ISO New England Inc. Transmission, Markets and Services Tariff (FERC Electric Tariff No.3) ("ISO Tariff").

The Regional Transmission and Operating Entities component of the EDC consists of all charges from ISO New England Inc. ("ISO"). These charges consist primarily of Regional Network Service, taken pursuant to the ISO Tariff. Other major costs (which are also billed by the ISO to UES) are various ancillary services allocated to transmission customers, such as VAR support, dispatch service, and black-start capability.

The Third Party Transmission Providers (NU Wholesale Distribution) component consists of Distribution Delivery Service ("DDS") charges with NU. DDS compensates Public Service Company of New Hampshire for the wheeling of power from the NU transmission system to UES's distribution system over certain facilities, which are classified as distribution facilities for accounting purposes and, therefore, are not included in the NU transmission system rate base.

Q. Please provide the External Delivery cost data, which was utilized in the calculation of the EDC.

A. Schedule TMB-2 provides the External Delivery cost data used in the calculation of the EDC. Page 2 provides actual historic External Delivery cost data for the year beginning August 2012 through July 2013. Actual External Delivery cost data for the months of August 2012 through April 2013 was included in UES's last rate and reconciliation filing, Docket No. DE 13-172. In that docket, UES provided estimated External Delivery costs for May 2013 through July 2013. Rather than present partial data beginning with May 2013, UES is presenting the full period. Page 3 of Schedule 2 provides External Delivery cost data for the current EDC rate period, August 2013 through July 2014. Actual cost data is available through April 2014, and estimated cost data is provided for May 2014 through July 2014. Finally, page 4 of Schedule TMB-2 provides estimated External Delivery costs for the upcoming EDC rate period, August 2014 through July 2015. These include costs associated with the recovery of a customer billing adjustment (column (o)) as approved in docket DE 11-105 and as discussed in the testimony of Ms. McNamara.

Q. Please provide a comparison of the External Delivery costs for the upcoming EDC rate period (August 2014 through July 2015) to the projected External Delivery costs for the current EDC rate period (August 2013 through July 2014).

A. Please refer to Table 2 below for an itemized comparison of estimated External Delivery cost for the upcoming EDC rate period to the projected External Delivery costs for the current rate period.

Table 2. Comparison of Estimated External Delivery costs for August 2014 through July 2015 to projected External Delivery costs for August 2013 through July 2014

Unitil Energy Systems, Inc.

Line No.	Line Item Description	Aug 2013 - July 2014 9 Months Act. and 3 Months Est.	Aug 2014 - July 2015 Estimate	Variance (Aug 2014 - July 2015 Costs minus Aug 2013 - July 2014 Costs)
1.	Third Party Transmission Providers (NU Network Integration Transmission Service)	($56,559)	$675,071	$731,630
2.	Regional Transmission and Operating Entities	$19,602,410	$20,328,068	$725,658
3.	Third Party Transmission Providers (NU Wholesale Distribution)	$2,980,566	$2,898,883	($81,683)
4.	Transmission-based Assessments and Fees	$10,000	$10,000	$0
5.	Load Estimation and Reporting System Costs	$196,005	$203,844	$7,839
6.	Data and Information Services	$15,000	$15,000	$0
7.	Legal Charges	$5,906	$40,000	$34,094
8.	Consulting Outside Service Charges	$5,000	$30,000	$25,000
9.	Administrative Service Charges	$6,959	$8,232	$1,273
10.	Non-Distribution Portion of the Annual PUC Assessment	$255,322	$233,754	($21,568)
11.	Working Capital Associated with Other Flow-Through Operating Expenses	$381,168	$381,168	$0
12.	Regional Greenhouse Gas Initiative Rebates	($380,000)	($1,140,000)	($760,000)
13.	Lost Distribution Revenue from Net Metering	$0	$18,724	$18,724
14.	EDC Cost Adjustment	$73,996	$73,996	$0
15.	Total External Delivery Costs	$23,095,772	$23,776,739	$680,967

Q. Please explain the projected increase in External Delivery costs of approximately $681,000 for the upcoming EDC rate period (August 2014 through July 2015) over the current EDC rate period (August 2013 through July 2014).

A. The increase in External Delivery costs for the upcoming EDC rate period is primarily the result of one factor: higher Regional Transmission and Operating Entities cost for the upcoming period of August 2014 through July 2015. The $681,000 increase in the Regional Transmission and Operating Entities costs is driven almost solely by an increase in the Regional Network Service ("RNS") rate from $85.32/kW-Year to $89.80/kW-Year effective June 1, 2014.

Q. What legal costs does UES expect to incur under the EDC?

A. UES estimates that it will incur approximately $40,000 in legal costs for the upcoming EDC rate period (August 2014 through July 2015). Legal costs include UES's estimates for monitoring FERC issuances and rulemakings and completing FERC tariff filings. EDC legal costs estimate excludes any charges directly related to the design and implementation of Default Service supply. Any legal costs associated with procurement of Default Service are recovered through the Default Service Charge.[2]

Q. Please provide the detail behind the estimate for the Administrative Service Charge.

A. Details regarding the ASC are provided in Schedule TMB-3 on lines 10 through 18. The ASC includes any costs incurred by UPC, relative to UPC's obligations

[2] This is in accordance with the settlement agreement approved in Docket No. DE 05-064.

under the Amended Unitil System Agreement, which are not otherwise assigned or assumed by UES. These costs include NEPOOL, ISO, and RTO costs, as well as legal, consulting, and other outside services. It does not include any internal costs of USC, UES or UPC.

Q. Has UES included Regional Greenhouse Gas Initiative (RGGI) rebates in the proposed EDC?

A. Yes. In accordance with NHPUC Order No. 25,664 issued on May 9, 2014 in DE 14-048, UES will include the rebate of excess 2014 RGGI auction proceeds applicable to all retail electric customers as a separate line item in the EDC. UES will record the rebates in the EDC in the month that the rebate amount is received, and apply carrying charges. With actual data through April 2014, however, UES has not yet received a rebate. Hence, in accordance with Order 25,664, it has included estimates of the four 2014 auction amounts in the EDC in order to ensure customers receive the credit, or estimate thereof, in a timely manner. These estimates are shown on Schedule TMB-2, Pages 3 and 4.

Q. Has UES included any new cost in this filing for which it is seeking recovery?

A. Yes. New to this filing is a proposal by the Company to recover the cost of Lost Distribution Revenue due to Net Metering Generation.

Q. Could you please explain why the Company is seeking recovery of this cost?

A. Due to the installation of customer-owned net metering generation, primarily solar facilities and some wind generation units, UES is receiving less distribution revenue than it would have in the absence of any net metered generation on the Company's distribution system. Because of the nature and installation of net metering units, energy generated by these facilities displaces energy that the electric utility customer would otherwise have had delivered to their location. As a result, UES received less distribution revenue than it would have absent net metering generation.

Q. Has UES prepared a calculation of the cost associated with net metering generation?

A. Yes. The calculation of this cost is arrived at as follows: (1) The size of each net metering generation unit installed on UES's system is used to determine an annual level of kWhs displaced by the net metering generation unit. (2) The annual level of kWhs displaced is then apportioned to each calendar month. (3) Distribution rates for Jan-13 through Apr-13 and May-13 through Dec-13 are used to assess the individual unit distribution revenues displaced by net metering generation. (4) Each net metering generation unit distribution revenues displaced is summed to arrive at the total cost. For calendar year 2013, the lost distribution revenue due to net metering generation on the Company's system is $18,724.[3] A detailed technical analysis of this calculation along with an explanatory statement is provided in Schedule TMB-6.

Q. Could you please explain the basis for including this cost in the EDC?

A. Certainly. The Commission's rules, specifically Puc 903.02 (o), state:

> ***"A distribution utility may perform an annual calculation to determine the net effect of net metering on its default service and distribution revenues and expenses in the prior calendar year. Pursuant to Puc 203, the commission shall determine by order, after notice and hearing, the utility-specific method of performing the calculation and applying the results, as well as a reconciliation mechanism to collect or credit any such net effects with appropriate carrying charges and credits applied."***

Accordingly, the Company is seeking to recover Lost Distribution Revenue from Net Metering Generation for calendar year 2013 of approximately $19,000 through its EDC. The Company has chosen the EDC as the mechanism to recover the cost of lost distribution revenue due to net metering generation for the following reasons: (1) the EDC is a charge used to recover various costs on a fully-reconciling basis with interest for any over or under-recoveries occurring in the prior year; (2) the EDC is a charge that is billed to all customers taking delivery service form UES and this is appropriate for recovery of lost distribution

[3] Please note that with respect to this calculation, the Company is reviewing customers that may have had excess generation and, therefore, displaced less distribution kWhs than they would have otherwise. This may result in a slightly lower figure and UES will provide an update during this proceeding.

revenue from net metering generation; and (3) the annual EDC charge is established in accordance with the procedures set forth in Puc 203.

The Company proposes to include in future annual EDC filings the cost of lost distribution revenue from net metering generation from the prior calendar year. For example, in its next annual EDC filing to be made in June 2015, UES would include the cost for calendar year 2014.

V. UPC COSTS AND REVENUES

Q. Has UPC prepared an accounting of the costs and revenues to UPC under the CRP and the ASC?

A. Yes. Schedule TMB-4 provides this accounting for the period beginning August 2012 through April 2014. UPC bills UES estimates of the CRP and ASC on the 25th of the month for the upcoming month. The estimated expenses are trued-up to actual expenses on a two-month lag basis. In order to calculate the true-up, UPC tracks the actual expenses, which comprise both the CRP and the ASC. These actual expenses are compared to the estimated expenses to calculate the true-up for prior period. Schedule TMB-4 provides summary data of actual CRP and ASC expenses and revenues.

VI. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.