UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

TODD M. BOHAN

New Hampshire Public Utilities Commission

Docket No.: DE 12-

June 15, 2012

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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 an 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.

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 12-003.

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, 2012. Ms. Linda S. McNamara presents the reconciliation for the SCC and EDC through July 2012 and the rate development for the SCC and EDC for the period beginning August 1, 2012 and ending July 31, 2013, 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 2010 through April 2012 and estimated data from May 2012 through July 2013. In addition, Schedule TMB-1, page 2 includes costs associated with the recovery of a customer billing adjustment pending in docket DE 11-105 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 is equal to the specified monthly payment stream made by UPC to Mirant Energy Trading, LLC ("MET"), pursuant to the Mirant Agreement, which continued through October 2010. The Mirant Agreement provided for the transfer of most of UPC's purchase power obligations to MET in exchange for fixed monthly payments from UPC.[1]

UPC's Residual Contract Obligations included contract buyout payments, which existed prior to the restructuring of the portfolio through the Mirant Agreement. The final contract buyout payment obligation was the Indeck contract buyout, which UPC completed in September 2009. The CRP estimates in this filing include no Residual Contract Obligations.

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

[1] The Mirant Agreement refers to the Portfolio Sale and Assignment and Transition Service and Default Service Supply Agreement by and among UPC, UES, and Mirant Americas Energy Marketing, LP. The Mirant Agreement was effective May 1, 2003 and also provided for the sale of Transition and Default Service power to UES through April 2006. Effective February 1, 2006, the Mirant Agreement was transferred to Mirant Energy Trading, LLC.

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 2010 through April 2012 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 2012 and ending July 2013 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 2012 through July 2013) to the projected CRP for the current SCC rate period (August 2011 through July 2012).

A. Table 1 provides a comparison of the estimated CRP for the upcoming SCC rate period (August 2012 through July 2013) to the projected actual CRP for the current SCC rate period (August 2011 through July 2012).

Table 1. Comparison of Estimated CRP for August 2012 through July 2013 to Projected CRP for August 2011 through July 2012
Unitil Power Corp.

Line No.	Line Item Description	Aug 2011 - July 2012 9 Months Act. and 3 Months Est.	Aug 2012 - July 2013 Estimate	Variance (Aug 2012 - July 2013 Costs minus Aug 2011 - July 2012 Costs)
1.	Portfolio Sales Charge	$0	$0	$0
2.	Residual Contract Obligations	$0	$0	$0
3.	Hydro-Quebec Support Payments	($125,623)	$173,652	$299,275
4.	Subtotal (L. 2 through 4)	($125,623)	$173,652	$299,275
5.	True-up for estimate	$343,987	$0	($343,987)
6.	Obligations prior to May 1, 2003	$0	$0	$0
7.	Total Contract Release Payments as billed by Unitil Power Corp.	$218,364	$173,652	($44,712)

At the time of the preparation of this estimate of the CRP, actual CRP expense data was available through April 2012. As such, the projected actual CRP for the current SCC rate period (August 2011 through July 2012) presented in Table 1 is comprised of nine months of actual data and three months estimated data.

Q. Please explain why there are no Portfolio Sales Charges or Residual Contract Obligations Charges.

A. 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.

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.[2] Please refer to Schedule TMB-5 for itemized cost and revenue offsets, related to the Hydro-Quebec Phase II Support Agreements.

[2] 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.

Q. Please provide an update of the Mirant Agreement.

A. Mirant has previously fulfilled the contractual obligations of each contract in the UPC portfolio, which was transferred to Mirant from UPC under the Mirant Agreement. UPC's payments to Mirant under the Mirant Agreement ended in October 2010.

V. 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 Costs - Renewable Source Option program;
10) Administrative Service Charges;
11) Non-Distribution Portion of the Annual PUC Assessment; and
12) Working Capital Associated with Other Flow-Through Operating Expenses.

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 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 2010 through July 2011. Actual External Delivery cost data for the months of August 2010 through April 2011 was included in UES's last rate and reconciliation filing, Docket No. DE 11-141. In that docket, UES provided estimated External Delivery costs for May 2011 through July 2011. Rather than present partial data beginning with May 2011, UES is presenting the full period. Page 3 of Schedule 2 provides External Delivery cost data for the current EDC rate period, August 2011 through July 2012. Actual cost data is available through April 2012, and estimated cost data is provided for May 2012 through July 2012. Finally, page 4 of Schedule TMB-2 provides estimated External Delivery costs for the upcoming EDC rate period, August 2012 through July 2013. These include costs associated with the recovery of a customer billing adjustment (column (n)) pending in docket DE 11-105 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 2012 through July 2013) to the projected External Delivery costs for the current EDC rate period (August 2011 through July 2012).

A. Please refer to the Table 2 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 2012 through July 2013 to projected External Delivery costs for August 2011 through July 2012
Unitil Energy Systems, Inc.

Line No.	Line Item Description	Aug 2011 - July 2012 9 Months Act. and 3 Months Est.	Aug 2012 - July 2013 Estimate	Variance (Aug 2012 - July 2013 Costs minus Aug 2011 - July 2012 Costs)
1.	Third Party Transmission Providers (NU Network Integration Transmission Service)	($240,037)	$1,335,671	$1,575,708
2.	Regional Transmission and Operating Entities	$14,431,261	$16,977,835	$2,546,574
3.	Third Party Transmission Providers (NU Wholesale Distribution)	$2,918,287	$2,823,954	($94,333)
4.	Transmission-based Assessments and Fees	$2,500	$2,500	$0
5.	Load Estimation and Reporting System Costs	$171,723	$168,000	($3,723)
6.	Data and Information Services	$15,000	$15,000	$0
7.	Legal Charges	$40,383	$59,493	$19,110
8.	Consulting Outside Service Charges	$2,118	$7,432	$5,314
9.	Administrative Costs - Renewable Source Option	$187	$500	$313
10.	Administrative Service Charges	$8,509	$7,286	($1,223)
11.	Non-Distribution Portion of the Annual PUC Assessment	$294,242	$274,662	($19,580)
12.	Working Capital Associated with Other Flow-Through Operating Expenses	$286,306	$286,306	$0
13.	EDC Cost Adjustment	$0	$48,526	$48,526
14.	Total External Delivery Costs	$17,930,479	$22,007,166	$4,076,687

Q. Please explain the projected increase in External Delivery costs of approximately $4 million for the upcoming EDC rate period (August 2012 through July 2013) over the current EDC rate period (August 2011 through July 2012).

A. The increase in External Delivery costs for the upcoming EDC rate period is primarily the result of two factors: (1) higher Third Party Transmission Providers (NU Network Integration Transmission Service) cost; and (2) higher Regional Transmission and Operating Entities cost for the upcoming period of August 2012 through July 2013. The variance in the NU Network Integration Transmission Service cost is driven in large part by a $1.04 million refund from NU in June 2012. The $2.5 million increase in the Regional Transmission and Operating Entities costs is driven almost solely by an increase in the in the Regional Network Service ("RNS") rate from $63.87/kW-Year to $75.05/kW-Year effective June 1, 2012.[3]

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

A. I estimate that UES will incur approximately $59,000 in legal costs for the upcoming EDC rate period (August 2012 through July 2013). Legal costs include UES's estimates for monitoring FERC issuances and rulemakings and compliance with FERC's electronic tariff requirements. 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.[4]

[3] This is a preliminary figure that is pending final approval by the Participating Transmission Owners Administrative Committee ("PTO-AC") on June 18, 2012.

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

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 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.

VI. 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 2010 through April 2012. 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.

VIII. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.