PASCOAG
UTILITY DISTRICT

coag Electric • Pascoag Water

253 Pascoag Main Street
P.O. Box 107
Pascoag, RI 02859
Phone: 401-568-6222
Fax: 401-568-0066
www.pud-ri.org

Pascoag Utility District

Electric Department

ADDENDUM FILING

IN RE: PASCOAG UTILITY DISTRICT'S
MID-YEAR STATUS REPORT
(STANDARD OFFER SERVICE, TRANSITION, AND TRANSMISSION)
RIPUC DOCKET #: 4454

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May 28, 2014

Rhode Island Public Utilities Commission
Ms. Luly Massaro, Commission Clerk
89 Jefferson Blvd.
Warwick, RI 02888

Re: Addendum: Mid-Year Filing for Standard Offer Service, Transition, and Transmission Reconciliation
RIPUC Docket No. 4454

Dear Ms. Massaro:

On behalf of Pascoag Utility District (Pascoag or PUD), we herewith submit an original and nine copies of Pascoag's Addendum to the Mid-Year Filing for Standard Offer Service, Transition, and Transmission Reconciliation. This submittal consists of three books:

Book 1	Testimony and Testimony Exhibits
Book 2	Supporting Schedules
Book 3	Purchase Power Invoices

In the original filing on April 25, 2014, Pascoag stated that it would supply the actual expenses and revenue for April prior to June's hearing. This Addendum Filing contains that reconciliation.

In this filing, Pascoag is requesting the following changes to its Standard Offer Service, Transition and Transmission Charges:

Factor	**Current**	**Proposed**	**Difference**
SOS	$0.07039	$0.07736	$0.00697
Transition	$0.00568	$0.00611	$0.00043
Transmission	$0.02488	$0.02913	$0.00425
Total	$0.10095	$0.11260	$0.01165

Under the current rate, a residential customer using 500 kilowatt-hours of electricity per month pays $77.23. Under the proposed rate, that customer would see his bill increase to $83.06, an increase of $5.83, or 7.6%.

The requested effective date for the new rate is July 1, 2014. If you have any questions, please do not hesitate to contact me.

Very truly yours,

Judith R Allaire

Judith R. Allaire
Assistant General Manager

Cc: Service list

Pascoag Utility District

Addendum to the Year End Status Report Compliance Tariff Filing – RIPUC No. 4454

Service List – 2014

Name	**E-mail**	**Phone/Fax**
Michael R. Kirkwood General Manager Pascoag Utility District P O Box 107 Pascoag, RI 02859	mkirkwood@pud-ri.org	(401) 568-6222 (401) 568-0066
Judith R. Allaire Assistant General Manager Pascoag Utility District P O Box 107 Pascoag, RI 02859	jallaire@pud-ri.org hround@pud-ri.org	(401) 568-6222 (401) 568-0066
William L. Bernstein, Esq. 627 Putnam Pike Greenville, RI 02828	wlblaw@verizon.net	(401) 949-2228 (401) 949-1680
Karen Lyons, Esq. Dept. of Attorney General 150 South Main Street Providence, RI 02903	klyons@riag.ri.gov psmith@dpuc.ri.gov steve.scialabba@dpuc.ri.gov jmunoz@riag.ri.gov dmacrae@riag.ri.gov jspirito@dpuc.ri.gov acontente@dpuc.ri.gov	(401) 222-2424
Original & nine (9) copies file with: Luly E. Massaro Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02889	Luly.massaro@puc.ri.gov Patricia.lucarelli@puc.ri.gov Sharon.ColbyCamara@puc.ri.gov Nicholas.ucci@puc.ri.gov	(401) 941-4500

CERTIFICATE OF SERVICE

I hereby certify that copy/copies of this Addendum to the Mid-Year Status Report, RIPUC Docket No. 4454 were served electronically on the individuals named in the above List of Recipients of Filing, this 28th day of May 2014.

Judith R. Allaire

Judith R. Allaire, Notary Public

My commission expires March 28, 2017

State of Rhode Island and Providence Plantations
PUBLIC UTILITIES COMMISSION

RE: PASCOAG UTILITY DISTRICT
RIPUC DOCKET NO. 4454

NOTICE OF CHANGE IN RATE

Pursuant to Rhode Island General Laws (R.I.G.L.), Section 39-3-11, and in accordance with Section 2.4 of the Rules of Practice and Procedure of the Rhode Island Public Utilities Commission (RIPUC), the Pascoag Utility District hereby gives notice of a proposed change in rates filed and published in compliance with R.I.G.L. 39-3-10.

The proposed changes are contained in the exhibits accompanying the filing. The new rates, as proposed, are to become effective July 1, 2014.

Standard Offer	Current	$0.07039	Proposed	$0.07736
Transition Charge	Current	$0.00568	Proposed	$0.00611
Transmission Charge	Current	$0.02488	Proposed	$0.02913
		$0.10095		$0.11260

A residential customer using 500 kilowatt-hours is currently paying $77.23. Under the proposed rates, this customer's bill would increase to $83.06, an increase of $5.83, or 7.6 %.

Be advised as follows:

1) Pascoag Utility District, incorporated by a special act of the General Assembly, is a quasi-municipal utility within the Village of Pascoag with offices located at 253 Pascoag Main Street, Pascoag, Rhode Island.
2) The Electric Department of the Pascoag Utility District operates an electric distribution system providing retail electric service to customers in the Villages of Pascoag and Harrisville, both in the Town of Burrillville, Rhode Island.
3) Correspondence for Pascoag Utility District in this case should be addressed to Michael R. Kirkwood, General Manager, Pascoag Utility District Electric Department, 253 Pascoag Main Street, P O Box 107, Pascoag, Rhode Island.
4) In accordance with the RIPUC Rules and Regulations, the documents accompanying this filing contain data and information in support of Pascoag Utility District's application. A copy of this filing is at our offices and may be examined by the public during business hours.

Michael R. Kirkwood

Michael R. Kirkwood, General Manager
Pascoag Utility District

STATE OF RHODE ISLAND
COUNTY OF PROVIDENCE
Subscribed and sworn to before me on May 28, 2014.

Judith R. Allaire

Judith R. Allaire, Notary Public
My commission expires March 28, 2017

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Pascoag Utility District – Electric Department

Mid-Year Filing for Standard Offer Service, Transmission and Transition Reconciliation

ADDENDUM FILING

RIPUC Docket No. 4454

Book 1

Testimony and Testimony Exhibits

Michael R. Kirkwood, General Manager

Judith R. Allaire, Assistant General Manager

<u>Q. Since filing your original testimony in RIPUC Docket #4454, has Pascoag sought to protect itself from market volatility in the upcoming period?</u>

<u>A.</u> Yes, Pascoag has been working intently with Energy New England (ENE) in order to further hedge our power supply position, both for the remainder of this year and for the period 2015 through 2017.

<u>Q. Why has Pascoag looked to hedge the remainder of its portfolio through 2017?</u>

<u>A.</u> Pascoag is concerned that the main driver of volatile pricing, especially in the winter months, will continue to be the lack of adequate natural gas pipeline capacity. As explained in my previous testimony, this inadequate gas infrastructure not only leads to excessive prices in the natural gas spot market, but also in the electricity spot markets in New England (Day Ahead and Real Time) which are driven by gas-fired generating units. Since major improvements in pipeline capacity are not projected to be in place until late 2017, at the earliest, Pascoag and ENE thought it would be best to protect Pascoag's remaining open position through that period.

<u>Q. Was Pascoag successful in obtaining a competitive supply to hedge its remaining open position?</u>

<u>A.</u> Yes, Pascoag and ENE first ran a solicitation for the 2015-17 time period by seeking a load following deal. A load following deal has the structure similar to our existing 2012-2014 agreement with Constellation Energy, except that we are seeking a 100% load-following hedge for the whole term of the agreement due to the volatility in future pricing. We are concerned that many other market participants who are not fully hedged may begin to seek to hedge their supplies, and may drive up future market prices as we move through the next several months. We wanted to act quickly before the market becomes overheated to the point where it turns completely into a "Seller's Market".

<u>Q. Please describe the solicitation and resulting deal that was confirmed for 2015-17.</u>

<u>A.</u> Pascoag and ENE queried several power suppliers in early April to provide fixed pricing for load following energy. Load following energy is calculated by taking Pascoag's actual day-to-day load requirement and subtracting the estimate of our other entitlements (Seabrook, NYPA, RISE, Miller Hydro, and Spruce Mountain Wind) to determine what our additional need is. We then asked for pricing that would fill 100% of this hour-by-hour need (load – existing supply). We received quotes from three of the supplier entities that were very competitive with the prices that ENE estimated for that period. After several rounds of negotiations and price improvement, Pascoag selected TransCanada Power Marketing Ltd. (TransCanada) as the supplier, at a fixed price of 7.03 cents/kWh for the 3-year period. This price will protect Pascoag from the volatility we saw this winter for the un-hedged portion or our portfolio, which oftentimes exceeded 25 cents/kWh on the spot market. Please see Exhibit MRK-1, which is a copy of the contract (called a Confirmation) with TransCanada.

<u>Q. Please describe the solicitation and resulting deal that was put in place for the remainder of 2014.</u>

<u>A.</u> Pascoag and ENE then strategized the best method to solicit a power supply for the unhedged portion or our existing 2014 program. Since only about 7% of our portfolio is unhedged for the remainder of 2014, and after ENE had consulted with various power suppliers about their interest, Pascoag and ENE determined that the small amount of power Pascoag needed for the remainder of 2014 would not result in competitive bids for load-following energy from the suppliers. We determined alternatively that the best bids would be made if we asked for blocks of energy for peak and off-peak periods. Again, after receiving bids from multiple suppliers, and engaging in negotiations and asking for best and final pricing, Pascoag received a solid bid on May 22nd for 4,157 MWhs at a set price of $65.65/MWh, or 6.565 cents/kWh delivered to the Mass. Hub. The winning bidder is Shell Energy North America (Shell). Although the Confirmation for this deal with Shell will be executed later this week, the deal was concluded by email on that day. Please see Exhibit MRK-2, which is a copy of the email agreement with Shell.

Q. Does this conclude your testimony?

A. Yes, it does.

TESTIMONY EXHIBITS – MICHAEL R. KIRKWOOD

EXECUTION COPY

Exhibit MRK-1

Confirmation Letter

This Confirmation (the "Confirmation") shall confirm the agreement reached on April 23, 2014 (the "Trade Date") between TransCanada Power Marketing Ltd. ("Seller") and Pascoag Utility District ("Pascoag") (each individually a "Party" and collectively the "Parties") regarding the purchase and sale of Load Following Energy, as more fully set forth herein. This Confirmation is being provided pursuant to and in accordance with the EEI Master Power Purchase and Sale Agreement dated December 7, 2010 (the "Master Agreement") between Seller and Pascoag and constitutes part of and is subject to the terms and provisions of such Master Agreement.

1. Definitions. Except as otherwise provided herein or in the Master Agreement, all product or market-related terms capitalized but not defined herein shall have the meaning given such terms (or any successor thereto) in the Applicable Market Rules as amended from time to time. Terms used but not defined herein shall have the meanings ascribed to them in the Master Agreement. In the event of a conflict between the terms of the Master Agreement and this Confirmation, the terms contained in this Confirmation shall control. In addition to the foregoing, the following terms shall have the meanings set forth herein.

1.1 "2x16 Energy" shall be Energy scheduled during 2x16 Hours.

1.2 "2x16 Hours" shall mean the hours beginning on HE 0800 through and including HE 2300 EPT on Saturday, Sunday and NERC Holidays.

1.3 "Applicable Market Rules" means Market Rule 1, the ISO-NE Information Policy, the ISO-NE Administrative Procedures, the ISO-NE Manuals and any other system rules, procedures or criteria for the operation and administration of the ISO-NE Market System and the ISO-NE Tariff.

1.4 "Confirmation" shall have the meaning given such term in the first paragraph of this Confirmation.

1.5 "DR Program" means any load interruption or demand-side management program imposed by applicable law or ISO-NE in accordance with Applicable Market Rules that affects the Pascoag Load Asset.

1.6 "Delivery Point" shall have the meaning set forth in Section 4 hereof.

1.7 "EPT" shall mean Eastern Prevailing Time, which shall be the local time in New York City on the date of determination.

1.8 "HE" shall mean hour ending.

1.9 "Hedged Percentage" shall mean one hundred percent (100%) of the gross hourly Energy requirements of Pascoag's ratepayers located in Pascoag's service territory as of the Trade Date.

1.10 "ISO-NE" means ISO-New England Inc. and its successors and assigns.

1.11 "IBT Container" shall mean the form of electronic contract submittal, as implemented by the ISO-NE Market System effective March 1, 2003, that only requires Pascoag to confirm the general parameters of the IBT and not the hourly schedules of Energy delivery.

1.12 "Load" means the RTLO of the Pascoag Load Asset, as measured at the interconnection point of Pascoag's system with National Grid, less the Pascoag Fixed Volumes. Load shall not include any capacity, ancillary services obligations, or renewable portfolio standards. In addition, and notwithstanding anything to the contrary in the Confirmation, Load shall not include any Load Following Energy requirements related to (i) any wholesale or aggregation transaction to which Pascoag is a Party; (ii) any change in customers as a result of any acquisition, divestiture, annexation, merger, joint venture, partnership, or other similar transaction that Pascoag may undertake on or after the Trade Date; or (iii) the addition of any single customer of Pascoag whose peak load in any single hour is greater than 1 MW. To the extent that Pascoag does incur such an additional load obligation because of the occurrence of one or more of the events contemplated in the prior sentence, such additional load obligation shall not be included in the Load and Seller shall have no responsibility to provide Load Following Energy for such load.

1.13 "Load Cap" shall mean 14 MW.

1.14 "Load Following Energy" shall mean the quantity of Energy required to serve the Hedged Percentage of the Pascoag Load Asset during each ISO-NE settlement interval including the Day-Ahead and the Real-Time Load Obligation associated with the Pascoag Load Asset.

1.15 "Master Agreement" shall have the meaning given such term in the first paragraph of this Confirmation.

1.16 "MW" shall mean megawatts.

1.17 "NERC" shall mean the North American Electric Reliability Corporation, including with any successors thereto.

1.18 "Operating Day" means the calendar day period beginning at HE 0100 EPT for which transactions in the New England Markets are scheduled.

1.19 "On-Peak Energy" shall be Energy scheduled during On-Peak Hours.

1.20 "On-Peak Hours" shall mean the hours beginning on HE 0800 EPT through and including HE 2300 EPT each day during the Supply Term except Saturday, Sunday and any holiday designated by NERC.

1.21 "Off-Peak Energy" shall be Energy scheduled during Off-Peak Hours.

1.22 "Off-Peak Hours" shall be those hours beginning on HE 2400 EPT through and including HE 0700 EPT each day during the Supply Term and shall include Saturday, Sunday and any holiday designated be NERC.

1.23 "Pascoag Estimated Load" shall have the meaning set forth in Section 3.3.

1.24 "Pascoag Fixed Volumes" shall mean the volumes, in megawatts, set forth on Schedule 1 hereto for On-Peak Energy, Off-Peak Energy and 2x16 Energy.

1.25 "Pascoag Load Quantity" shall have the meaning set forth in Section 3.2 hereof.

1.26 "Purchase Price" shall have the meaning set forth in Section 5 hereof.

1.27 "RTLO" shall mean the Real Time Load Obligation, as defined by the ISO-NE Rules.

1.28 "Supply Term" shall have the meaning set forth in Section 2 hereof.

2. Supply Term. Seller's obligation to sell Load Following Energy, as defined in this Confirmation, and Pascoag's obligation to purchase Load Following Energy is effective as of the Trade Date. The period during which Seller shall sell and Buyer shall purchase Load Following Energy shall commence on HE 0100 EPT, on January 1, 2015 and shall terminate at the end of HE 2400, EPT, on December 31, 2017 (the "Supply Term") unless earlier terminated pursuant to the Master Agreement; provided that the applicable provisions of this Confirmation shall continue in effect after termination or expiration hereof to the extent necessary to provide for accountings, final billing, billing adjustments, resolution of any billing dispute, resolution of any court or administrative proceeding and payments

3. Purchase and Sale of Load Following Energy.

3.1 Load Following Energy. During the Supply Term, Pascoag shall schedule and purchase and TransCanada shall confirm and sell Load Following Energy at the Delivery Point at the price set forth on Exhibit A for On-Peak Hours, Off-Peak Hours and 2x16 Hours in accordance with ISO-NE Rules, all as more fully set forth in this Confirmation.

3.2 Load Asset. Pascoag has established a Load Asset in the ISO-NE Market System, with such Load Asset being designated as Load Asset #159 (the "Pascoag Load Asset"). The Pascoag Load Asset includes transmission and distribution losses from the ISO-NE Pool Transmission Facilities (as defined in the ISO-NE Rules) to the retail meters for Pascoag's retail customers and shall be used to determine the Load. Pascoag shall report, or cause to be reported, the quantity of Load to ISO-NE (the "Pascoag Load Quantity") and to Seller in accordance with ISO-NE Rules..

3.3 Scheduling of Energy. Pascoag shall schedule Load Following Energy in accordance with Section 3.3.1. If Pascoag does not know the actual amount of the RTLO in time to schedule the Load Following Energy on the day after the Operating Day, Pascoag shall schedule an estimated amount of Energy that reasonably approximates Pascoag's RTLO based upon information available to it at the time of scheduling (the "Pascoag Estimated Load"). If Pascoag's actual Load differs from the Pascoag Estimated Load, Seller and Pascoag shall settle such difference in accordance with Section 3.3.2. All Energy scheduled on the day after the Operating Day shall be scheduled at the Day-Ahead Locational Marginal Price for the Delivery

Point for the hour that the Energy was consumed. Unless the Parties agree otherwise, Pascoag shall schedule Energy by submitting one IBT Container for each month during the Supply Term.

3.3.1 Load Calculation. Pascoag shall calculate the amount of Load for each hour of each Operating Day according to the following formula; provided, however, if during any hour, the result of subtracting the Pascoag Fixed Volumes from the product of the Pascoag Load Quantity and the Hedged Percentage is negative then Seller shall sell 0.0 MW to Pascoag and Pascoag shall purchase 0.0 MW from Seller during such hour(s):

Load = (Pascoag Load Quantity * (Hedged Percentage) – Pascoag Fixed Volumes

3.3.2 Settlement of Pascoag Estimated Load. In the event that Pascoag schedules an amount of Energy that is different than the amount of Load in any hour on an Operating Day, Seller shall credit or charge Pascoag an amount equal to the product of (i) the hourly difference obtained by subtracting the amount of Energy scheduled and confirmed, if any, from the Load in such hour, and (ii) the Day Ahead Locational Marginal Price at the Delivery Point for such hour, as determined by ISO-NE in accordance with the Applicable Market Rules for the hours when Pascoag over-scheduled or under-scheduled the Load hereunder. If the foregoing product is negative, such amounts shall be a charge to Pascoag and if such amount is positive, such amount shall be a credit to Pascoag.

3.4 Sales for Resale. Notwithstanding anything to the contrary in this Confirmation, all sales of Load Following Energy hereunder shall be sales for resale and Pascoag shall continue to be responsible for furnishing retail service to its retail customers in accordance with applicable laws and requirements, at its sole cost and expense. For the avoidance of doubt, Pascoag shall bear all administrative costs associated with retail service, including, but not limited to billing, customer service, and meter reading.

4. Delivery Point. Pascoag shall schedule all deliveries of Load Following Energy to the Massachusetts Trading Hub (ISO-NE Node #4000) (the "Delivery Point"). Seller shall bear all costs and losses of supplying Load Following Energy hereunder to the Delivery Point and Pascoag shall bear all costs and losses at and after the Delivery Point. Title to all Load Following Energy shall pass at the Delivery Point.

5. Purchase Price. Pascoag shall pay Seller, each month during the Supply Term, an amount equal to the product of the Load delivered pursuant to the calculation in Section 3.3.1 and the price set forth on Exhibit A for such month (the "Purchase Price").

6. Load Growth.

6.1 Changes in Service Territory; Additional Customers; Load Cap. Notwithstanding anything to the contrary in this Confirmation, Seller shall not be obligated to sell and deliver Load Following Energy for any changes to the Load resulting from any Load in excess of the Load Cap. To the extent that Pascoag does incur such an additional load obligation in excess of the Load Cap, such additional load obligation shall not be included in the Load and Seller shall have no responsibility to provide Load Following Energy for such load.

6.2 Warranty and Representation Regarding DR Program. Pascoag represents and warrants to Seller as of the Trade Date that to the best of its knowledge and belief there are no DR Programs being considered by Pascoag or that may be imposed on Pascoag during the Supply Term. If Pascoag becomes involuntarily subject to any DR Program then Pascoag shall provide Seller with the earlier of (i) sixty (60) days or (ii), in the event that such DR Programs are implemented in less than 60 days, as soon as practicable, advance written notice of such requirements and provide a description of such DR Program in reasonable detail.

6.3 Voluntary Demand Response. Prior to Pascoag instituting any DR Program, Pascoag will provide at least 60 days advance written notice to Seller of such DR Program and a description of such DR Program in reasonable detail. In addition, (i) if such DR Program would reduce Load by more than 1 MWs in any hour, whether alone or aggregated with other DR Programs, or (ii) Pascoag implements DR Programs such that the total curtailment associated therewith is greater than 100 hours per calendar year, then Seller and Pascoag agree to meet to discuss whether changes should be made to the prices set forth in Exhibit A and if so the actual changes. If the Parties are unable to agree then Seller may terminate this Confirmation upon 30 days' prior written notice. For clarity, the foregoing shall not apply to any DR Program implemented directly by any of Pascoag's customers.

[Signature page contained on next page]

Agreed to as of the date set forth above.

TRANSCANADA POWER MARKETING LTD.

By:
Its:

By:
Its:

PASCOAG UTILITY DISTRICT, RHODE ISLAND

Michael R. Kirkwood
By: Michael R. Kirkwood
Its: General Manager/CEO

Agreed to as of the date set forth above.

TRANSCANADA POWER MARKETING LTD.

By: Geoff Murray
Its: Vice President
Western Power
Growth

By: Richard Schuler
Its: As Agent and Attorney-In-Fact

PASCOAG UTILITY DISTRICT, RHODE ISLAND

By:
Its:

Business	
Legal	

SCHEDULE 1

Fixed Volumes

Pascoag's "FIXED" Supply Volumes for 2015			
	PEAK	7x8	2x16
Jan	3.641	3.295	3.292
Feb	3.673	3.317	3.286
Mar	4.971	3.356	4.292
Apr	5.084	3.494	4.492
May	4.844	3.222	4.219
Jun	5.044	3.299	4.270
Jul	4.937	3.363	4.326
Aug	4.842	3.432	4.405
Sep	4.816	3.429	4.405
Oct	3.437	2.077	3.034
Nov	4.673	3.293	4.278
Dec	3.386	3.129	3.111

Pascoag's "FIXED" Supply Volumes for 2016

	PEAK	7x8	2x16
Jan	3.641	3.295	3.292
Feb	3.673	3.317	3.286
Mar	4.971	3.356	4.292
Apr	5.084	3.494	4.492
May	4.844	3.222	4.219
Jun	4.825	3.076	4.039
Jul	4.790	3.211	4.169
Aug	4.728	3.308	4.260
Sep	4.668	3.280	4.263
Oct	4.468	3.104	4.057
Nov	4.510	3.129	4.113
Dec	3.201	2.940	2.922

Pascoag's "FIXED" Supply Volumes for 2017

	PEAK	7x8	2x16
Jan	3.446	3.102	3.094
Feb	3.507	3.153	3.123
Mar	4.734	3.119	4.051
Apr	3.638	2.053	3.054
May	4.591	2.973	3.979
Jun	4.825	3.076	4.039
Jul	4.790	3.211	4.169
Aug	4.728	3.308	4.260
Sep	4.668	3.280	4.263
Oct	4.468	3.104	4.057
Nov	4.510	3.129	4.113
Dec	3.201	2.940	2.922

EXHIBIT A

Pricing

Fixed price of $70.30/MWh for all months in the Supply Term.

Exhibit MRK-2

From: Michael Kirkwood
Sent: Thursday, May 22, 2014 12:09 PM
To: 'Gil Myette'; Susan.E.Smith@shell.com
c: robin.battersby@shell.com; GXTRInsideSalesUSPower@shell.com
Subject: RE: Pascoag Quotes

Susan,

Thanks for working with us on this. I agree on behalf of Pascoag Utility District to the structure and pricing below.

Mike Kirkwood

Michael R. Kirkwood
General Manager/CEO
Pascoag Utility District

Office: 401-568-6222

From: Gil Myette [mailto:gmyette@energynewengland.com]
Sent: Thursday, May 22, 2014 12:08 PM
To: Susan.E.Smith@shell.com
Cc: robin.battersby@shell.com; GXTRInsideSalesUSPower@shell.com
Subject: RE: Pascoag Quotes

Susan,

I agree. Thanks for your help and patience in getting this deal to completion.

Regards,

Gil Myette
Energy New England
Office: 508-698-1221
Cell: 508-250-8051

From: Susan.E.Smith@shell.com [mailto:Susan.E.Smith@shell.com]
Sent: Thursday, May 22, 2014 12:00 PM
To: Gil Myette
Cc: robin.battersby@shell.com; GXTRInsideSalesUSPower@shell.com
Subject: RE: Pascoag Quotes

Please confirm this is your understanding of the transaction. Shell sells to Pascoag the below listed blocks (4,157 mwhs) at ISONE MassHub at $65.65, da phys.

Date	7x16	7x8
Jun-14	0.5	1.0
Jul-14	0.5	1.0
Aug-14	0.5	1.0
ep-14	0.5	1.0
Oct-14	0.5	1.0
Nov-14	1.25	1.0

Dec-14	1.25	1.0

Glad we got one done! Please let us know if you need anything else. We appreciate your business!

san Smith
Sales Representative | Shell Energy North America
Office: 315.423.4817 | **Mobile:** 315.317.0364 | **Fax:** 713.265.2153
AIM: scurrierstgp | **Address:** 4 Clinton Square, Suite 101, Syracuse, NY 13202, USA
E-mail: susan.e.smith@shell.com | **Web:** www.shell.com

From: Gil Myette [mailto:gmyette@energynewengland.com]
Sent: Thursday, May 22, 2014 10:59 AM
To: Smith, Susan E SENA-STE/34
Cc: Battersby, Robin SENA-STE/36
Subject: RE: Pascoag Quotes

Thanks Susan,

I'll get back to you shortly.

Gil Myette
Energy New England
Office: 508-698-1221
Cell: 508-250-8051

From: Susan.E.Smith@shell.com [mailto:Susan.E.Smith@shell.com]
nt: Thursday, May 22, 2014 10:55 AM
To: Gil Myette
Cc: robin.battersby@shell.com
Subject: RE: Pascoag Quotes

Good Morning Gil,

We just got the ok to trade green light. Listed below are our refreshed, indicative da phys offers.

4,157 MWHS
MHUB: $65.85
RI: $66.75

Date	7x16	7x8
Jun-14	0.5	1.0
Jul-14	0.5	1.0
Aug-14	0.5	1.0
Sep-14	0.5	1.0
Oct-14	0.5	1.0
Nov-14	1.25	1.0
Dec-14	1.25	1.0

Thanks!
Susan Smith

Sales Representative | **Shell Energy North America**
Office: 315.423.4817 | **Mobile:** 315.317.0364 | **Fax:** 713.265.2153
AIM: scurrierstgp | **Address:** 4 Clinton Square, Suite 101, Syracuse, NY 13202, USA
E-mail: susan.e.smith@shell.com | **Web:** www.shell.com

From: Gil Myette [mailto:gmyette@energynewengland.com]
Sent: Thursday, May 22, 2014 10:23 AM
To: Smith, Susan E SENA-STE/34
Cc: Battersby, Robin SENA-STE/36
Subject: RE: Pascoag Quotes

Good Morning Susan,

It looks like we are almost there with the contract. In an effort to move the process forward, could you please provide current indicative quotes for the June-Dec 2014 tranche.

Thanks for the help.

Regards,

Gil Myette
Energy New England
Office: 508-698-1221
Cell: 508-250-8051

From: Susan.E.Smith@shell.com [mailto:Susan.E.Smith@shell.com]
Sent: Monday, May 12, 2014 10:04 AM
To: Gil Myette
Cc: robin.battersby@shell.com
Subject: FW: Pascoag Quotes

Good Moring Gil,

I will be providing DA PHYS pricing on May 20th at MHUB and RI for below listed shape but please let me know if you would like any indicative pricing before then!

Thank you,

Susan Smith
Sales Representative | **Shell Energy North America**
Office: 315.423.4817 | **Mobile:** 315.317.0364 | **Fax:** 713.265.2153
AIM: scurrierstgp | **Address:** 4 Clinton Square, Suite 101, Syracuse, NY 13202, USA
E-mail: susan.e.smith@shell.com | **Web:** www.shell.com

From: Gil Myette [mailto:gmyette@energynewengland.com]
nt: Wednesday, May 07, 2014 03:54 PM
: Battersby, Robin SENA-STE/36
Cc: Tim Hebert <thebert@energynewengland.com>; Jim MacDonald <jmacdonald@energynewengland.com>; Hartnett, John W SENA-STE/36

Subject: Pascoag Quotes

Good Afternoon Robin,

On behalf of the Pascoag Utility District I'm pleased to include you in this request for pricing. Pascoag is looking to purchase the following MW volumes as shown in the table below.

Date	7x16	7x8
Jun-14	0.5	1.0
Jul-14	0.5	1.0
Aug-14	0.5	1.0
Sep-14	0.5	1.0
Oct-14	0.5	1.0
Nov-14	1.25	1.0
Dec-14	1.25	1.0

We request that you provide quotes for the blocks at 10:00 a.m. on Tuesday, May 20th. Pascoag desires a single price for the entire term. Please provide quotes (MA Hub and the RI Load Zone) for Physical delivery in the DA Market, FIRM LD. After analyzing the offers, we anticipate agreeing a deal that same day. However, we understand the market may be volatile and will ask for re-freshed pricing before finalizing any agreement.

As always, Pascoag reserves the right to take any action that it deems to be in its best interest.

anks for your attention to this matter and we look forward to reviewing your quotes on May 20th.

Please let me know if you have any questions or comments.

Regards,

Gil Myette
Energy New England
Office: 508-698-1221
Cell: 508-250-8051

Testimony and Testimony Exhibits

Judith R. Allaire

Q. Please update the Commission on the reason for this addendum filing.

A. In the original filing, submitted April 25, 2014, Pascoag used actual expenses and revenue for January, February and March. Revenue and expenses were estimated for the month of April, and Pascoag stated that it would provide actual revenue and expenses for April, prior to the hearing, as soon as they were available. The addendum filing contains the actual expenses and revenue for the month of April.

Q. How does the reconciliation for April impact this filing?

A. In the original filing, the estimate for April's purchase power expense was $419,248. The actual expense for the month of April was $403,994, or $15,254 under the forecast.

The revenue for April was estimated at $433,574, based on sales of 4,294,941 kilowatt-hours. This estimate was based on historical usage for the prior two-year period. The actual revenue for April was $444,044 with total sales of 4,398,652. Actual revenue was $10,470 above the forecast. Based on the updated information, the estimated under collection is reduced from $756,208 to $730,484.

Q. Is there anything else included in the April filing?

A. Because of the timing of the submittal on April 25th, Pascoag had not received the actual National Grid LNS Transmission invoice for March or the MMWEC Administrative Fee invoice for March and estimates were used. In April, the adjustments were made to correct those two invoices to reflect the actual amounts. (See **Addendum Testimony Exhibit JRA-1**) The changes are documented below:

Invoice	March – Estimate	March– Actual	Component
National Grid – LNS	$21,500	$47,401	Transmission
MMWEC – Admin Fee	$ 100	$ 94	SOS

Q. In earlier pre-filed testimony, Pascoag stated that high transmission costs associated with the delivery of the NYPA entitlements impacted the under collection. Please update the Commission on the status of the most current NYPA costs.

A. The NYPA invoice for April, while lower than the most recent period, was still higher than what we typically see. Historically, NYPA power is between 2.5 to 3.0 cents per kilowatt-hour. The transmission component on the entitlement drove that cost up to 6.5 to 10.0 cents per kilowatt-hour for the first quarter of 2014. The table below, shows the impact of increased transmission cost over the period.

Month	Entitlement	Demand	Energy	Transmission	Total	Kwhrs Purchased	Cost per Kwhr
January	Niagara	$2,737	$1,908	$18,900	$23,545	388,000	0.0607
	St Lawrence	$6,256	$4,256	$45,038	$55,550	865,000	0.0642
February	Niagara	$2,737	$1,717	$30,697	$35,151	349,000	0.1007
	St Lawrence	$6,256	$4,246	$53,378	$63,880	863,000	0.0740
March	Niagara	$2,737	$1,801	$27,921	$32,459	366,000	0.0887
	St Lawrence	$6,256	$4,856	$65,274	$76,386	987,000	0.0774
April	Niagara	$2,737	$1,771	$14,249	$18,757	360,000	0.0520
	St Lawrence	$6,256	$6,322	$34,569	$47,147	1,285,000	0.0370

Q. Was there any other unusual activity in April that resulted in lower than forecast energy and transmission expense?

A. An item that impacted the April expense was a reduction to the Project Six – Seabrook – invoice. A typical Project Six invoice (net of the Surplus Fund Credit) is approximately $80,000. The invoice for the April billing period was $51,929. The reduced invoice was reflective of a credit related to the United States Department of Energy reimbursements to Seabrook for costs incurred during 2012 related to the Dry Fuel Storage Facility.

Q. In the original filing, Pascoag used a growth rate of one percent based on improvements to the economic climate. Has Pascoag noticed any increased energy sales or purchases that supports this assumption?

A. Sales for the first four months of 2014 support Pascoag's assumption. The colder winter weather may account for some increase in sales, but since Pascoag uses a three-year average any fluctuations should level out.

Month	**Forecast [1] (3 year average)**	**Actual[2] (3 year average)**	**Difference**
January 2014	4,952	5,176	224
February 2014	4,761	4,898	137
March 2014	4,192	4,308	116
April 2014	4,278	4,330	52
Total	18,183	18,712	529

Additionally, Pascoag's Peak Demand History supports this assumption. This schedule is attached as **Addendum Testimony Exhibit JRA-2.**

This assumption reflects the fact that Danielle International will continue to operate in its Pascoag facility through the remainder of 2014. To the best of our knowledge, this is an accurate assumption.

Q. Based on the updated information included in the addendum, what are the charges requested by Pascoag for the Standard Offer Service, Transition and Transmission Charges and what is the requested effective date?

A. The rates requested by Pascoag are for an effective date of July 1, 2014:

Factor	Current	Requested	Difference
SOS	$0.07039	$0.07736	$0.0697
Transition	$0.00568	$0.00611	$0.0043
Transmission	$0.02488	$0.02913	$0.0425
Total	$0.10095	$0.11260	$0.01165

Q. What impact will the requested rates have to a typical residential customer?

---

[1] From Pascoag's December 2013 filing, Schedule F-2, Line 112

[2] From Pascoag's Addendum 2014 filing, Schedule E, Lines 46-49

A. Under the current rate, an average residential customer using 500 kilowatt-hours of electricity pays $77.23 per month. Under the proposed rate, that customer would see his monthly electric bill increase to $83.06, an increase of $5.83, or 7.6%.

Q. Please provide a brief update of the financial issues discussed in the original filing.

A. ***Issue 1* – Drawdown of Purchase Power Restricted Fund (PPRF):** The initial concern was two substantial withdrawals from the PPRF to meet purchase power payment requirements in January ($180,000) and February ($155,000), and the District's ability to "repay" that withdrawal. Also a concern was the possibility of additional withdrawals to meet future power bills.

As of this date, no additional withdrawals have been required, but we have not been able to begin the reimbursement process to the account. However, the monthly transfers of base rate revenues from Danielle International, as required as a settlement stipulation from Pascoag's COS study, have been made. Activity to the PPRF is documented below:

Purchase Power Restrict Fund		**Balance 1/1/2014**	**$497,983**
Month	**Deposit**	**Withdrawal**	**Balance**
January	$18,230	$180,000	$336,213
February	$18,230	$155,000	$199,443
March	$18,230		$217,673
April	$18,230		$235,903
May	$18,230		$254,133

***Item 2* – Funding the annual requirements for the Restricted Fund for Capital Projects:** The concern was Pascoag's ability to meet the annual funding requirement of $306,000. Historically, Pascoag tries to "level fund" this account at a monthly rate of $25,500. That was not possible for the first four months of 2014. While this under funding during the winter period by itself is not concerning, combined with all the other financial issues facing Pascoag at the time, it did become a more pressing issue. In May, Pascoag made a deposit of $30,000 to the Restricted Fund, which is a positive direction. The current intent is to continue this process so that by year-end, the annual goal of $306,000 will be met. Pascoag will provide Division and Commission staff with the quarterly reporting requirements as set forth in the settlement agreement. Activity to the Restricted Fund is listed below:

Restricted Fund		Balance 1/1/2014	$491,214
Month	Deposits	Withdrawals	Balance
January	$15,000	$76,036	$430,178
February	$10,000	$ 7,679	$432,499
March	$20,000	$ 4,154	$448,345
April	$20,000		$468,345
May	$30,000	$11,386	$486,959

***Item 3* – Account Payable open obligations:** The situation regarding Pascoag's non-power vendors over the winter was another item of concern, as at times, our open account payable balance was past due. During April and May, the District was able to bring all vendors within thirty day terms.

Q. Does this conclude your testimony?

A. Yes, it does.

Addendum Testimony Exhibit JRA-1

		April 2014 ACTUAL			
Energy Component	**Kwhrs**	**Standard Offer**	**Transmission**	**Total**	**Average**
MMWEC - Project 6	0				
Project 6	155,761	$ 57,644.68	$ 66.16	$ 57,710.84	
Credit		$ (5,781.60)		$ (5,781.60)	
Total MMWEC-Project 6	**155,761**	**$ 51,863.08**	**$ 66.16**	**$ 51,929.24**	**$ 0.3334**
MMWEC Non-PSA					
Admin Exp		$ 83.70		$ 83.70	
Correct Admin Fee - March		**$ 94.02**		**$ 94.02**	
Back Out March Admin Fee Estimate		**$ (100.00)**		**$ (100.00)**	
NYPA Forward Capacity Market				$ -	
ISO-NY Expenses				$ -	
HQI			$ 1,076.24	$ 1,076.24	
HQII				$ -	
HQIII				$ -	
Total MMWEC Non PSA		**$ 77.72**	**$ 1,076.24**	**$ 1,153.96**	
NYPA - Firm & Peaking					
Demand				$ -	
Energy	1,645,000	$ 17,086.40	$ 48,818.55	$ 65,904.95	
NYISO Ancillary				$ -	
Transmission				$ -	
ISO True up Charges/credits				$ -	
Total NYPA	**1,645,000**	**$ 17,086.40**	**$ 48,818.55**	**$ 65,904.95**	**$ 0.0401**
National Grid					
Correct LNS - March			**$ 47,401.19**	**$ 47,401.19**	
Back out LNS March Estimate			**$ (21,500.00)**	**$ (21,500.00)**	
Direct Assignment Facilities (DAR)			$ 6,379.00	$ 6,379.00	
LNS - APRIL ESTIMATE			**$ 21,500.00**	**$ 21,500.00**	
Total National Grid			**$ 53,780.19**	**$ 53,780.19**	
Energy New England					
ISO Interchange	336,750	$ 43,009.91	$ 82,511.04	$ 125,520.95	
ENE All Requirements		$ 6,785.00		$ 6,785.00	
Capacity Market Purchases		$ -		$ -	
Capacity Market Sales		$ -		$ -	
ISO Load Base Charges		$ -		$ -	
ISO Scheduled Charges		$ -		$ -	
Domonion		$ 14,040.00		$ 14,040.00	
Miller Hydro	178,478	$ 10,235.68		$ 10,235.68	**$ 0.0573**
Spruce Mountain	142,462	$ 14,139.39		$ 14,139.39	**$ 0.0993**
Spruce Mt. REC Sales		$ (28,092.92)		$ (28,092.92)	
Spruce Mt REC Fee		$ 199.08		$ 199.08	
Constellation/Exelon	1,097,239	$ 63,841.94		$ 63,841.94	**$ 0.0582**
Exelon - Financial Settlement		$ 342.74		$ 342.74	**#DIV/0!**
NExtEra	480,000	$ 19,649.45		$ 19,649.45	**$ 0.0409**
NextEra Fixed Montly Cost		$ 4,470.00		$ 4,470.00	
UCAP Purchases - NextEra		$ 94.37		$ 94.37	
Total -Energy New England	**2,234,929**	**$ 148,714.64**	**$ 82,511.04**	**$ 231,225.68**	
APRIL COST	**4,035,690**	**$ 217,741.84**	**$ 186,252.18**	**$ 403,994.02**	**$ 0.1001**
ESTIMATES - APRIL					
NYPA Interruptible Kwhrs:		**Month**	**Y-T-D**		
Niagara		16,000	178,000		
St Lawrence		500,000	950,000		
TRUE-UP - MARCH					

Peak Demand

Addendum Testimony Exhibit JRA-2

Pascoag Utility District
Peak Demand Summary

	2006	2007	2008	2009	2010	2011	2012	2013	2014
Jan	9262	9176	9563	8419	8962	10002	9732	10340	10899
Feb	9412	9468	9118	9358	8856	9958	9202	9782	10093
March	8976	9283	8425	8991	8453	8651	9019	9549	10135
April	7941	7985	6969	7252	7330	7910	8821	8581	
May	7756	7987	6941	7167	9683	8609	9775	10595	
June	9797	10291	12065	7648	10991	10241	11853	11450	
July	11424	9987	10376	9627	12355	12765	12235	13578	
August	11944	11062	9656	11075	11379	10786	11620	10235	
Sept	8463	9450	9048	8319	11606	8679	10036	11563	
October	8120	7789	8235	8510	8362	8539	8326	8375	
Nov	8948	8750	8976	8347	8835	9048	9796	9874	
Dec	9212	10285	9656	9726	10015	9874	10171	11649	
	Winter Peak			11.6		Dec-13			
	Summer Peak			13.6		Jul-13			

PASCOAG
UTILITY DISTRICT

coag Electric • Pascoag Water

253 Pascoag Main Street
P.O. Box 107
Pascoag, RI 02859
Phone: 401-568-6222
Fax: 401-568-0066
www.pud-ri.org

Pascoag Utility District – Electric Department

Mid-Year Filing for Standard Offer Service, Transmission and Transition Reconciliation

ADDENDUM FILING

RIPUC Docket No. 4454

Book 2 – Schedules A - H

RIPUC Docket No. 4454

Pascoag Utility District

Addendum Filing

Schedule A

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1							Pascoag Utility District - Electric Department										
2							Summary of Purchase Power Costs (1)										
3																	
4			Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Total		
5						ACTUAL	ESTIMATE	ESTIMATE									
6	Purchased Energy (kWhrs)																
7		NYPA	1,253,000	1,212,000	1,353,000	1,645,000	1,237,000	1,197,000							7,897,000		
8		Seabrook	990,464	894,972	986,642	155,761	973,000	942,000							4,942,839		
9		Miller Hydro Group	159,431	108,645	117,686	178,478	181,000	145,000							890,240		
10		Spruce Mnt	177,645	152,068	179,844	142,462	132,000	84,000							868,019		
11		Spruce Mnt REC Sales													0		
12		ENE All Requirements													0		
13		Exelon/Constellation	2,135,920	1,728,485	1,708,807	1,097,239	910,000	1,266,000							8,846,451		
14		NextEra Energy	400,000	400,000	400,000	480,000	496,000	480,000							2,656,000		
15		NextEra Mthly Fixed													0		
16		NextEra UCAP													0		
17		Dominion UCAP													0		
18		ISO Monthly Charges													0		
19		ISO Weekly Activity	490,180	345,580	428,880	336,750	423,000	669,000							2,693,390		
20		ISO Annual Fee															
21		MH CM Credit															
22	Total Kwhrs		5,606,640	4,841,750	5,174,859	4,035,690	4,352,000	4,783,000	0	0	0	0	0	0	28,793,939	(A3, Line 167)	
23													Kwhr Proof		28,793,939	(Schedule D) ✓	
24																	
25	Purchased Power Expense																
26		NYPA	$ 15,157.76	$ 14,956.04	$ 15,649.76	$ 17,086.40	$ 15,217.00	$ 15,020.00							$ 93,086.96		
27		Seabrook	$ 82,027.80	$ 93,904.94	$ 88,306.44	$ 51,863.08	$ 87,677.00	$ 87,424.00							$ 491,203.26		
28		Seabrook Surplus Credit	$ (5,781.60)	$ (5,781.60)	$ (5,781.60)										$ (17,344.80)		
29		MMWEC Admin Fee	$ 191.93	$ 122.52	$ 100.00	$ 83.70	$ 100.00	$ 100.00							$ 698.15		
30		Admin Fee Adjust				$ (5.98)									$ (5.98)		
31		MMWEC FCM Credit			$ (322.68)										$ (322.68)		
32		Miller Hydro Group	$ 9,143.37	$ 6,230.82	$ 6,748.73	$ 10,235.68	$ 10,357.00	$ 8,304.00							$ 51,019.60		
33		Spruce Mnt	$ 17,631.27	$ 15,092.71	$ 17,849.49	$ 14,139.39	$ 13,101.00	$ 8,369.00							$ 86,182.86		
34		Spruce Mnt REC Sales	$ (20,088.72)		$ -	$ (28,092.92)	$ (14,143.00)								$ (62,324.64)		
35		Spruce Mnt REC Fee	$ 142.36		$ -	$ 199.08									$ 341.44		
36		ENE All Requirements	$ 6,785.00	$ 6,785.00	$ 6,785.00	$ 6,785.00	$ 6,580.00	$ 6,580.00							$ 40,300.00		
37		Exelon	$ 125,493.72	$ 101,735.89	$ 100,332.81	$ 64,184.68	$ 51,666.00	$ 72,776.00							$ 516,189.10		
38		NextEra Energy	$ 60,784.64	$ 63,602.21	$ 43,326.61	$ 19,649.45	$ 23,209.00	$ 24,506.00							$ 235,077.91		
39		NextEra Mthly Fixed	$ 4,470.00	$ 4,470.00	$ 4,470.00	$ 4,470.00									$ 17,880.00		
40		NextEra UCAP	$ 106.31	$ 94.38	$ 94.37	$ 94.37									$ 389.43		
41		Dominion UCAP	$ 14,040.00	$ 14,040.00	$ 14,040.00	$ 14,040.00	$ 14,040.00	$ 14,040.00							$ 84,240.00		
42		ISO Monthly Charges	$ 33,731.30	$ 37,621.35	$ 22,235.66	$ 43,009.91	$ 15,372.00	$ 39,693.00							$ 191,663.22		
43		ISO Charges				$ -	$ 10,354.00	$ 19,715.00							$ 30,069.00		
44		ISO Capacity Market				$ -	$ 26,737.00	$ 21,219.00							$ 47,956.00		
45		ISO Weekly Activity	$ 132,435.89	$ 85,360.02	$ 43,457.01										$ 261,252.92		
46		ISO Annual Fee	$ 5,339.62												$ 5,339.62		
47		MH CM Credit	$ (533.01)	$ (555.41)	$ (529.19)										$ (1,617.61)		
48		Transmission	$ 180,507.99	$ 198,899.95	$ 204,004.16	$ 186,252.18	$ 106,259.00	$ 118,915.00							$ 994,838.28		
49																	
50	Total Expense		$ 661,585.63	$ 636,578.82	$ 560,766.57	$ 403,994.02	$ 366,526.00	$ 436,661.00	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,066,112.04	(A2, Line 109)	
51													Revenue Proof:		$ 3,066,112.04		
52																	
53																	
54	*Market Value is based on the aggregate amount of Pascoag's required payments under the PSA's and PPA's, exclusive of the Reserve and Contingency Fund billings,*																
55	*to MMWEC at December 31, 2013. These amounts are from Pascoag's audited financial statements.*																
56															-		
57																	
58	2014 aggregate amount		$46,917	$46,917	$46,917	$46,917	$46,917	$46,917							$281,500		
59	Cumulative carry over - 12/2013*		($10,816)	($10,816)	($10,816)	($10,816)	($10,816)	($10,816)							($64,895)		
60	Monthly Transition Exp.		$36,101	$36,101	$36,101	$36,101	$36,101	$36,101	$0	$0	$0	$0	$0	$0	$216,605		
61		**Cumulative Carry Over - See Schedule C-3, Line 83*											Revenue Proof:		$216,605		
62																	
63	(1) Information on Schedule A-1 is from Pascoag's Summary of Purchased Power Invoices, submitted under separate cover as "Book 3"																A-1

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
64								Restated Purchase Power Costs									
65																	
66																	
67																	
68			Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Total		
69						ACTUAL	ESTIMATE	ESTIMATE									
70								Restated Costs (Dollars) -									
71		**Transition:**													$ -		
72	Monthly Transition Charge		$46,917	$46,917	$46,917	$46,917	$46,917	$46,917							$281,500		
73																	
74	**Restated Transition Cost**		**$46,917**	**$46,917**	**$46,917**	**$46,917**	**$46,917**	**$46,917**							**$ 281,500.00**		
75																	
76																	
77																	
78		**Transmission**	$ 180,507.99	$ 198,899.95	$ 204,004.16	$ 186,252.18	$ 106,259.00	$ 118,915.00							$ 994,838.28		
79																	
80	**Net Transmission**		**$ 180,507.99**	**$ 198,899.95**	**$ 204,004.16**	**$ 186,252.18**	**$ 106,259.00**	**$ 118,915.00**							**$ 994,838.28**		
81																	
82		**Restated Costs (Dollars) Standard Offer**															
83		NYPA	$ 15,157.76	$ 14,956.04	$ 15,649.76	$ 17,086.40	$ 15,217.00	$ 15,020.00							$ 93,086.96		
84		Seabrook	$ 82,027.80	$ 93,904.94	$ 88,306.44	$ 51,863.08	$ 87,677.00	$ 87,424.00							$ 491,203.26		
85		Seabrook Surplus Credit	$ (5,781.60)	$ (5,781.60)	$ (5,781.60)	$ -	$ -	$ -							$ (17,344.80)		
86		MMWEC Admin Fee	$ 191.93	$ 122.52	$ 100.00	$ 83.70	$ 100.00	$ 100.00							$ 698.15		
87		Admin Fee Adjust				$ (5.98)									$ (5.98)		
88		MMWEC FCM Credit			$ (322.68)										$ (322.68)		
89		Miller Hydro Group	$ 9,143.37	$ 6,230.82	$ 6,748.73	$ 10,235.68	$ 10,357.00	$ 8,304.00							$ 51,019.60		
90		Spruce Mnt	$ 17,631.27	$ 15,092.71	$ 17,849.49	$ 14,139.39	$ 13,101.00	$ 8,369.00							$ 86,182.86		
91		Spruce Mnt REC Sales	$ (20,088.72)	$ -	$ -	$ (28,092.92)	$ (14,143.00)	$ -							$ (62,324.64)		
92		Spruce Mnt REC Fee	$ 142.36	$ -	$ -	$ 199.08	$ -	$ -							$ 341.44		
93		ENE All Requirements	$ 6,785.00	$ 6,785.00	$ 6,785.00	$ 6,785.00	$ 6,580.00	$ 6,580.00							$ 40,300.00		
94		Exelon	$ 125,494	$ 101,736	$ 100,333	$ 64,185	$ 51,666	$ 72,776							$ 516,189.10		
95		NextEra Energy	$ 60,784.64	$ 63,602.21	$ 43,326.61	$ 19,649.45	$ 23,209.00	$ 24,506.00							$ 235,077.91		
96		NextEra Mthly Fixed	$ 4,470.00	$ 4,470.00	$ 4,470.00	$ 4,470.00	$ -	$ -							$ 17,880.00		
97		NextEra UCAP	$ 106.31	$ 94.38	$ 94.37	$ 94.37	$ -	$ -							$ 389.43		
98		Dominion UCAP	$ 14,040	$ 14,040	$ 14,040	$ 14,040	$ 14,040	$ 14,040							$ 84,240.00		
99		ISO Monthly Charges	$ 33,731	$ 37,621	$ 22,236	$ 43,010	$ 15,372	$ 39,693							$ 191,663.22		
100		ISO Charges				$ -	$ 10,354	$ 19,715							$ 30,069.00		
101		ISO Capacity Market				$ -	$ 26,737	$ 21,219							$ 47,956.00		
102		ISO Weekly Activity	$ 132,436	$ 85,360	$ 43,457	$ -	$ -	$ -							$ 261,252.92		
103		ISO Annual Fee	$ 5,340	$ -	$ -	$ -	$ -	$ -							$ 5,339.62		
104		MH CM Credit	$ (533)	$ (555)	$ (529)	$ -	$ -	$ -							$ (1,617.61)		
105	Sub-Total		$ 481,077.64	$ 437,678.87	$ 356,762.41	$ 217,741.84	$ 260,267.00	$ 317,746.00							$ 2,071,273.76		
106	Market Value (Transition)		($46,917)	($46,917)	($46,917)	($46,917)	($46,917)	($46,917)							$ (281,500.00)		
107	**Restated Cost - SOS**		**$ 434,160.97**	**$ 390,762.20**	**$ 309,845.74**	**$ 170,825.17**	**$ 213,350.33**	**$ 270,829.33**							**$ 1,789,773.76**		
108																	
109	**Restated Power Costs**		**$ 661,585.63**	**$ 636,578.82**	**$ 560,766.57**	**$ 403,994.02**	**$ 366,526.00**	**$ 436,661.00**							**$ 3,066,112.04**	(A1, Line 50)	
110													**Revenue Proof:**		**$ 3,066,112.04**		
111																	
112																	
113																	
114																	
115																	
116																	
117																	
118																	
119																	
120																	
121																	
122																	
123																	
124																	
125																	A-2
126																	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
127							Pascoag Utility District - Electric Department										
128							Summary of Revenue and Expenses										
129																	
130																	
131																	
132			Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Total		
133			**New Rates**														
134			**Pro-Rated**			**ACTUAL**	**ESTIMATE**	**ESTIMATE**									
135							(E, Line 50)	(E, Line 51)									
136	**Energy Sales to Consumers:**																
137	Kwhrs sold (1)		5,613,673	5,252,029	4,463,971	4,398,652	4,087,513	4,324,068							28,139,906		
138	Current Cost Recovery(kWhr sales*rate)																
139	Transition		$62,532.90	$29,832	$25,355	$24,984	$23,217	$24,561							$190,481.90		
140	Standard Offer		$239,867.22	$369,690	$314,219	$309,621	$287,720	$304,371							$1,825,488.76		
141	Transmission		$140,425.06	$130,670	$111,064	$109,438	$101,697	$107,583							$700,877.74		
142	**Total**		**$442,825.18**	**$530,192**	**$450,638**	**$444,044**	**$412,634**	**$436,515**							**$2,716,848.40**		
143													**Revenue Proof:**		**$2,716,848.40**		
144																	
145	**Over/(Under) Recovery Reconciliation**																
146			**$ (218,760.45)**	**$ (106,386.49)**	**$ (110,128.70)**	**$ 40,049.90**	**$ 46,108.44**	**$ (146.34)**							**$ (349,263.64)**	(C1, Line 103) ✓	
147																	
148																	
149																	
150	**Purchased Energy: (kWhrs)**														**Total**		
151		NYPA	1,253,000	1,212,000	1,353,000	1,645,000	1,237,000	1,197,000							7,897,000		
152		Seabrook	990,464	894,972	986,642	155,761	973,000	942,000							4,942,839		
153		Miller Hydro Group	159,431	108,645	117,686	178,478	181,000	145,000							890,240		
154		Spruce Mnt	177,645	152,068	179,844	142,462	132,000	84,000							868,019		
155		Spruce Mnt REC Sales													0		
156		ENE All Requirements													0		
157		Exelon	2,135,920	1,728,485	1,708,807	1,097,239	910,000	1,266,000							8,846,451		
158		NextEra Energy	400,000	400,000	400,000	480,000	496,000	480,000							2,656,000		
159		NextEra Mthly Fixed													0		
160		NextEra UCAP													0		
161		Dominion UCAP													0		
162		ISO Monthly Charges													0		
163		ISO Weekly Activity	490,180	345,580	428,880	336,750	423,000	669,000							2,693,390		
164		ISO Annual Fee													0		
165		MH CM Credit													0		
166	**Total Purchased Kwhrs**		**5,606,640**	**4,841,750**	**5,174,859**	**4,035,690**	**4,352,000**	**4,783,000**							**28,793,939**	(A1, Line 22)	
167													**Kwhr Proof:**		**28,793,939**		
168	**Energy Sales to Consumers: (kWhrs)**																
169		Sales	5,613,673	5,252,029	4,463,971	4,398,652	4,087,513	4,324,068							28,139,906		
170		street lights	67,992	57,034	56,462	47,630	50,000	48,000							327,118		
171	**Total Kwhr Sales**		**5,681,665**	**5,309,063**	**4,520,433**	**4,446,282**	**4,137,513**	**4,372,068**							**28,467,024**		
172													**Kwhr Proof:**		**28,467,024**		
173																	
174																	
175	**System Kwhr losses**		75,025	467,313	(654,426)	410,592	(214,487)	(410,932)							(326,915)		
176	**Percent Line Losses**		1.34%	9.65%	-12.65%	10.17%	-4.93%	-8.59%							-1.14%		
177																	
178																	
179																	
180																	
181																	
182	**(1)**	**See Schedule B for Sales to Customers**															
183																	
184																	
185																	
186																	
187																	A-3

RIPUC Docket No. 4454

Pascoag Utility District

Addendum Filing

Schedule B

For Billing month: April 2014

Code	Kw	Kwhrs	Demand/ Distribution	Renewable	Transmission	Transition	Conservation	Cust Chg	Stand Offer	Street Lt**	Sales Tax	Power Ftr	Other	Total	# Cust
Res		2,468,486	$ 96,815.66	$ 740.55	$ 61,415.93	$ 14,021.00	$ 4,936.97	$ 24,138	$ 173,756.73				$ 300.00	$ 376,124.84	4023
Comm		286,943	$ 12,040.13	$ 86.08	$ 7,139.14	$ 1,629.84	$ 573.89	$ 7,800	$ 20,197.92		$ 7,801.42			$ 57,268.41	520
Indus	6,047.15	1,643,223	$ 61,983.29	$ 492.97	$ 40,883.39	$ 9,333.51	$ 3,286.45	$ 6,991	$ 115,666.47			$ 321.99	-805.59	$ 238,152.96	62
New Rate	-													$ -	4605
SL		47,630												$ -	
Total	**6,047.15**	**4,446,282**	**$ 170,839.08**	**$ 1,319.60**	$ 109,438.46	$ 24,984.34	$ 8,797.30	$ 38,928.50	$ 309,621.11	$ 7,586.52	$ 7,801.42	$ 321.99	$ (505.59)	**$ 679,132.74**	
		(47,630)													
sales	w/o st lights	**4,398,652**													

Transmission	$ 109,438.46
Transition	$ 24,984.34
Stand Offer	$ 309,621.11
Revenue	$ 444,043.92

Schedule B- 4

RIPUC Docket No. 4454

Pascoag Utility District

Addendum Filing

Schedule C

	A	B	C	D	E	F	G	H	I	J
62									**Schedule C-1**	
63									**Page 2**	
64										
65										
66			**Combined Standard Offer, Transition Charge, and Transmission Charge**							
67		**Start Bal**	**Revenue**	**Expense**		**Monthly**	**Cumulative**			
68										
69	Jan-13	$688,182	$465,175	$603,453		($138,278)	$549,903			
70	Feb-13	$549,903	$459,212	$404,699		$54,513	$604,418	pro-rated - new rates		
71	Mar-13	$604,418	$300,335	$504,762		($204,427)	$399,991			
72	Apr-13	$399,991	$324,870	$372,310		($47,440)	$352,551			
73	May-13	$352,551	$318,027	$398,061		($80,034)	$272,517			
74	Jun-13	$272,517	$306,601	$427,313		($120,711)	$151,805			
75	Jul-13	$151,805	$367,490	$509,357		($141,867)	$9,939			
76	Aug-13	$9,939	$440,577	$410,149		$30,429	$40,367			
77	Sep-13	$40,367	$352,227	$389,621		($37,394)	$2,974			
78	Oct-13	$2,974	$309,332	$366,543		($57,211)	($54,237)			
79	Nov-13	($54,237)	$332,189	$430,078		($97,889)	($152,126)			
80	Dec-13	($152,126)	$332,370	$561,464		($229,094)	($381,220)			
81										
82		Period Cumulative Over/(Under) collection				($1,069,404)				
83										
84	Forecast Cumulative Over/(Under) Collection at 12/31/2013						($381,220)			
85										
86										
87			**Combined Standard Offer, Transition Charge, and Transmission Charge**							
88		**Start Bal**	**Revenue**	**Expense**		**Monthly**	**Cumulative**			
89										
90	Jan-14	($381,220)	$442,825	$ 661,586		($218,760)	($599,981)	pro-rated (new rates)		
91	14-Feb	($599,981)	$530,192	$ 636,579		($106,386)	($706,367)			
92	Mar-14	($706,367)	$450,638	$ 560,767		($110,129)	($816,496)			
93	14-Apr	($816,496)	$444,044	$ 403,994		$40,050	($776,446)			
94	May-14	($776,446)	$412,634	$ 366,526		$46,108	($730,338)			
95	14-Jun	($730,338)	$436,515	$ 436,661		($146)	($730,484)			
96	Jul-14									
97	14-Aug									
98	Sep-14									
99	14-Oct									
100	Nov-14									
101	14-Dec									
102										
103		Period Cumulative Over/(Under) collection				($349,264)		(A3, Line 146)		
104										
105	Forecast Cumulative Over/(Under) Collection at 6/30/2014						($730,484)			

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	A	B	C	D	E	F	G	H	I
62									
63									**Schedule C-2**
64									**Page 2**
65									
66									
67					**Standard Offer**				
68									
69		**Start Bal**	**Revenue**	**Expense**		**Monthly**	**Cumulative**		
70	Jan-13	$393,538	$287,062	$435,182		($148,120)	$245,418		
71	Feb-13	$245,418	$273,748	$261,631		$12,118	$257,535	pro-rated - new rates	
72	Mar-13	$257,535	$145,793	$262,556		($116,763)	$140,773		
73	Apr-13	$140,773	$157,966	$207,499		($49,534)	$91,239		
74	May-13	$91,239	$154,403	$221,910		($67,507)	$23,732		
75	Jun-13	$23,732	$148,856	$274,897		($126,041)	($102,309)		
76	Jul-13	($102,309)	$178,405	$346,626		($168,221)	($270,530)		
77	Aug-13	($270,530)	$213,902	$231,129		($17,227)	($287,757)		
78	Sep-13	($287,757)	$171,008	$232,745		($61,738)	($349,495)		
79	Oct-13	($349,495)	$150,182	$201,117		($50,935)	($400,430)		
80	Nov-13	($400,430)	$161,279	$269,383		($108,104)	($508,534)		
81	Dec-13	($508,534)	$161,367	$377,798		($216,432)	($724,966)		
82									
83		Period Cumulative Over/(Under) collection				($1,118,504)			
84									
85	Forecast Cumulative Over/(Under) Collection at 12/31/2013						($724,966)		
86									
87					**Standard Offer**				
88									
89		**Start Bal**	**Revenue**	**Expense**		**Monthly**	**Cumulative**		
90	14-Jan	($724,966)	$239,867	$ 434,161		($194,294)	($919,260)		
91	14-Feb	($919,260)	$369,690	$ 390,762		($21,072)	($940,332)		
92	14-Mar	($940,332)	$314,219	$ 309,846		$4,373	($935,958)		
93	14-Apr	($935,958)	$309,621	$ 170,825		$138,796	($797,162)		
94	14-May	($797,162)	$287,720	$ 213,350		$74,370	($722,793)		
95	14-Jun	($722,793)	$304,371	$ 270,829		$33,542	($689,251)		
96	14-Jul								
97	14-Aug								
98	14-Sep								
99	14-Oct								
100	14-Nov								
101	14-Dec								
102									
103		Period Cumulative Over/(Under) collection				$35,715			
104									
105	Forecast Cumulative Over/(Under) Collection at 6/30/214						($689,251)		

	A	B	C	D	E	F	G	H	I
62									
63									**Schedule C-3**
64									**Page 2**
65			**Transition Charge**						
66									
67		**Start Bal**	**Revenue**	**Expense**		**Monthly**	**Cumulative**		
68	Jan-13	$28,832	$56,682	$49,750		$6,932	$35,764		
69	Feb-13	$35,764	$59,618	$49,750		$9,868	$45,632	pro-rated - new rates	
70	Mar-13	$45,632	$51,635	$49,750		$1,885	$47,517		
71	Apr-13	$47,517	$55,753	$49,750		$6,003	$53,520		
72	May-13	$53,520	$54,672	$49,750		$4,922	$58,442		
73	Jun-13	$58,442	$52,708	$49,750		$2,958	$61,399		
74	Jul-13	$61,399	$63,179	$49,750		$13,429	$74,829		
75	Aug-13	$74,829	$75,739	$49,750		$25,989	$100,818		
76	Sep-13	$100,818	$60,551	$49,750		$10,801	$111,619		
77	Oct-13	$111,619	$53,177	$49,750		$3,427	$115,046		
78	Nov-13	$115,046	$57,106	$49,750		$7,356	$122,402		
79	Dec-13	$122,402	$57,137	$49,750		$7,387	$129,790		
80									
81		Period Cumulative Over/(Under) collection				$100,958			
82									
83	Forecast Cumulative Over/(Under) Collection at 12/31/2013						$129,790		
84									
85			**Transition Charge**						
86									
87		**Start Bal**	**Revenue**	**Expense**		**Monthly**	**Cumulative**		
88	14-Jan	$129,790	$62,533	$46,917		$15,616	$145,406		
89	14-Feb	$145,406	$29,832	$46,917		($17,085)	$128,321		
90	14-Mar	$128,321	$25,355	$46,917		($21,561)	$106,760		
91	14-Apr	$106,760	$24,984	$46,917		($21,932)	$84,827		
92	14-May	$84,827	$23,217	$46,917		($23,700)	$61,128		
93	14-Jun	$61,128	$24,561	$46,917		($22,356)	$38,772		
94	14-Jul								
95	14-Aug								
96	14-Sep								
97	14-Oct								
98	14-Nov								
99	14-Dec								
100									
101		Period Cumulative Over/(Under) collection				($91,018)			
102									
103	Forecast Cumulative Over/(Under) Collection at 6/30/2014						$38,772		

	A	B	C	D	E	F	G	H	I
62									
63									**Schedule C-4**
64									**Page 2**
65									
66			**Transmission Charge**						
67		**Start Bal**	**Revenue**	**Expense**		**Monthly**	**Cumulative**		
68	Jan-13	$265,813	$121,432	$118,522		$2,910	$268,723		
69	Feb-13	$268,723	$125,846	$93,319		$32,527	$301,249	pro-rated - new rates	
70	Mar-13	$301,249	$102,906	$192,456		($89,550)	$211,700		
71	Apr-13	$211,700	$111,152	$115,061		($3,909)	$207,791		
72	May-13	$207,791	$108,952	$126,401		($17,449)	$190,342		
73	Jun-13	$190,342	$105,038	$102,666		$2,372	$192,713		
74	Jul-13	$192,713	$125,906	$112,981		$12,925	$205,639		
75	Aug-13	$205,639	$150,936	$129,270		$21,666	$227,305		
76	Sep-13	$227,305	$120,669	$107,126		$13,543	$240,848		
77	Oct-13	$240,848	$105,973	$115,676		($9,702)	$231,146		
78	Nov-13	$231,146	$113,804	$110,945		$2,859	$234,004		
79	Dec-13	$234,004	$113,866	$133,916		($20,050)	$213,954		
80									
81		Period Cumulative Over/(Under) collection				($51,859)			
82									
83	Forecast cumulative Over/(Under) Collection at 6/30/214						$213,954		
84									
85			**Transmission Charge**						
86		**Start Bal**	**Revenue**	**Expense**		**Monthly**	**Cumulative**		
87	14-Jan	$213,954	$140,425	$ 180,508		($40,083)	$173,871		
88	14-Feb	$173,871	$130,670	$ 198,900		($68,229)	$105,642		
89	14-Mar	$105,642	$111,064	$ 204,004		($92,941)	$12,701		
90	14-Apr	$12,701	$109,438	$ 186,252		($76,814)	($64,113)		
91	14-May	($64,113)	$101,697	$ 106,259		($4,562)	($68,674)		
92	14-Jun	($68,674)	$107,583	$ 118,915		($11,332)	($80,006)		
93	14-Jul								
94	14-Aug								
95	14-Sep								
96	14-Oct								
97	14-Nov								
98	14-Dec								
99									
100		Period Cumulative Over/(Under) collection				($293,961)			
101									
102	Forecast cumulative Over/(Under) Collection at 6/30/2014						($80,006)		

RIPUC Docket No. 4454

Pascoag Utility District

Addendum Filing

Schedule D

Reconciliation of Forecast to Actual

Month	Budget (1)	Actual	Difference	Energy (MWH) Budget (1)	Energy (MWH) Actual (2)	Difference (Energy)	Actual Cost MWH	Budget Cost MWH
Jan 2014	$499,876	$661,586	$161,710	5,130	5,607	477	$118.00	$97.44
Feb 2014	$513,795	$636,579	$122,784	4,561	4,842	281	$131.48	$112.65
Mar 2014	$475,835	$560,767	$84,932	4,679	5,175	496	$108.36	$101.70
Apr 2014	$419,248	$403,994	($15,254)	4,162	4,036	(126)	$100.11	$100.73
May 2014	$366,526	$366,526	$0	4,352	4,352	0	$84.22	$84.22
Jun 2014	$436,661	$436,661	$0	4,783	4,783	0	$91.29	$91.29
Mid-Year Total	**$2,711,941**	**$3,066,112**	**$354,171**	**27,667**	**28,794**	**1,127**	**$106.48**	**$98.02**
Jul 2014	$514,592		($514,592)	6,043		(6,043)	#DIV/0!	$85.16
Aug 2014	$468,412		($468,412)	5,373		(5,373)	#DIV/0!	$87.18
Sep 2014	$411,632		($411,632)	4,608		(4,608)	#DIV/0!	$89.33
Oct 2014	$ 379,482		($379,482)	4,422		(4,422)	#DIV/0!	$85.82
Nov 2014	$ 373,517		($373,517)	4,547		(4,547)	#DIV/0!	$82.15
Dec-14	$ 466,143		($466,143)	5,107		(5,107)	#DIV/0!	$91.28
Total	$5,325,719	$3,066,112	($2,259,607)	57,767	28,794	(28,973)	$106.48	$92.19
					"Average" MWH cost		$106.48	$92.19

(1) From 12/2013 filing, Schedule F

(2) See A1, Line 23

D

RIPUC Docket No. 4454

Pascoag Utility District

Addendum Filing

Schedule E

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													**Schedule E**
2													
3			**Summary of Energy Sales to Customers Fiscal Year 2012**										
4			**2012**		**2011**		**2010**			**3-Year Average**			
5	January		4,840		4,940		5,100			4,960			
6	February		4,231		4,840		4,128			4,399			
7	March		4,352		4,116		3,812			4,093			
8	April		4,152		4,245		4,424			4,274			
9	May		3,826		3,759		3,453			3,679			
10	June		4,455		3,826		4,070			4,117			
11	July		4,684		4,862		5,074			4,874			
12	August		5,271		5,118		5,462			5,284			
13	September		5,715		5,319		5,062			5,365			
14	October		3,914		3,920		4,245			4,027			
15	November		4,157		3,922		3,754			3,944			
16	December		4,744		4,477		4,482			4,568			
17	Adjustment to COS - RY									(154)			
18	DPI adjustment									(7,500)			
19			54,342		53,345		53,066			45,931	(Please see		
20											Schedule DGB-2a		
21	Annual Total Sales - Based on forecast for Rate Year in Pascoag's COS Study										COS)		
22	No Growth Factor												
23	Annual Forecast Sales - 2013									45,931			
24													
25			**Summary of Energy Sales to Customers Fiscal Year 2013**										
26			**2013**		**2012**		**2011**			**3-Year Average**			
27	January		5074		4,840		4,940			4,952			
28	February		5212		4,231		4,840			4,761			
29	March		4108		4,352		4,116			4,192			
30	April		4438		4,152		4,245			4,278			
31	May		4349		3,826		3,759			3,978			
32	June		4193		4,455		3,826			4,158			
33	July		5026		4,684		4,862			4,858			
34	August		6025		5,271		5,118			5,471			
35	September		4817		5,715		5,319			5,284			
36	October		4230		3,914		3,920			4,022			
37	November		4543		4,157		3,922			4,207			
38	December		4546		4,744		4,477			4,589			
39			56,563		54,342		53,345			54,750			
40													
41	No Growth Factor												
42	Annual Sales - 2014									54,750			
43													
44			**Summary of Energy Sales to Customers Fiscal Year 2014**										
45			**2014**		**2013**		**2012**			**3-Year Average**			
46	January		5614		5074		4,840			5176			
47	February		5252		5212		4,231			4898			
48	March		4464		4108		4,352			4308			
49	April		4399		4438		4,152			4330			
50	May				4349		3,826			4088	2 year average		A3,Line 137 ✓
51	June				4193		4,455			4324	2 year average		A3,Line 137 ✓
52													
53	July				5026		4,684			4855	2 year average		
54	August				6025		5,271			5648	2 year average		
55	September				4817		5,715			5266	2 year average		
56	October				4230		3,914			4072	2 year average		
57	November				4543		4,157			4350	2 year average		
58	December				4546		4,744			4645	2 year average		
59			19728		56,563		54,342			28,837			F2,Line 113

RIPUC Docket No. 4454

Pascoag Utility District

Addendum Filing

Schedule F

	A	B	C	D	E	F	G	H	I
1									**Schedule F-1**
2									
3	**Pascoag Utility District**								
4	**Forecast Purchased Power Costs (1)**								
5		**Resources**	**Jul 2014**	**Aug 2014**	**Sept 2014**	**Oct 2014**	**Nov 2014**	**Dec 2014**	**Period Total**
6			(MWH)	(MWH)	(MWH)	(MWH)	(MWH)	(MWH)	
7			**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	
8		NYPA - Firm	1,228	1,228	1,188	1,228	1,188	1,228	7,288
9		Seabrook	973	973	942	973	942	973	5,776
10	**Sub-total Base**		**2,201**	**2,201**	**2,130**	**2,201**	**2,130**	**2,201**	**13,064**
11		Capacity Market Sales							
12		Capacity Market Purchases							
13		Dominion Capacity Purchase							-
14		NextEra RISE Purchase	496	496	480	496	480	496	2,944
15		Miller Hydro	95	84	68	104	137	137	625
16		Spruce Mt.	91	97	125	154	160	186	813
17		Constellation Bal Power Pur	1,834	1,816	1,001	752	788	1,079	7,270
18		Constellation Laod Following	288	287	228	218	219	247	1,487
19	**Sub-total Intermediate**		**2,804**	**2,780**	**1,902**	**1,724**	**1,784**	**2,145**	13,139
20		NYPA - Peak	9	9	9	9	9	**9**	**54**
21	**Sub-total Peaking**		**9**	**9**	**9**	**9**	**9**	**9**	**54**
22		ISO Energy Net Interchange	1,029	383	567	488	624	752	**3,843**
23		**Total MWH Purchased**	**6,043**	**5,373**	**4,608**	**4,422**	**4,547**	**5,107**	**30,100**
24		**Purchased Power Cost**							
25		NYPA Firm	$ 14,774	$ 14,774	$ 14,579	$ 14,774	$ 14,579	$ 14,774	$ 88,254
26	(T)	**NYPA Transmission**	$ **18,000**	$ **14,000**	$ **10,000**	$ **7,500**	$ **6,000**	$ **20,000**	$ **75,500**
27	**(2)**	Seabrook	$ 81,677	$ 81,677	$ 81,424	$ 81,677	$ 81,424	$ 81,677	$ 489,556
28	(T)	**Seabrook Transmission**	$ **69**	$ **69**	$ **69**	$ **69**	$ **69**	$ **69**	$ **414**
29	**Sub-total Base**		**$ 114,520**	**$ 110,520**	**$ 106,072**	**$ 104,020**	**$ 102,072**	**$ 116,520**	**$ 653,724**
30		Capacity Market Sales	($10,030)	($10,030)	($10,030)	($10,030)	($10,030)	($10,030)	($60,180)
31		Capacity Market Purchases	$ 31,249	$ 31,249	$ 31,249	$ 31,249	$ 31,249	$ 31,249	$ 187,494
32		Dominion Capacity Purchase	$ 14,040	$ 14,040	$ 14,040	$ 14,040	$ 14,040	$ 14,040	$ 84,240
33		NextEra RISE Purchase	$ 25,270	$ 25,294	$ 23,128	$ 23,727	$ 28,807	$ 42,650	$ 168,876
34		Miller Hydro	$ 5,447	$ 4,834	$ 3,896	$ 5,987	$ 7,851	$ 7,885	$ 35,900
35		Spruce Mt.	$ 9,014	$ 9,627	$ 12,359	$ 15,273	$ 15,880	$ 18,438	$ 80,591
36		REC Quarterly credit		$ (23,469)			$ (21,294)		$ (44,763)
37		Constellation Bal Power Pur	$ 109,847	$ 108,802	$ 59,972	$ 45,048	$ 47,190	$ 64,657	$ 435,516
38		Constellation Load Following	$ 13,479	$ 13,415	$ 10,653	$ 10,214	$ 10,245	$ 11,537	$ 69,543
39		ISO Energy Net Interchange	$ 56,751	$ 27,004	$ 21,026	$ 16,945	$ 29,662	$ 55,867	$ 207,255
40	**Sub-total Intermediate**		**$ 255,067**	**$ 200,766**	**$ 166,293**	**$ 152,453**	**$ 153,600**	**$ 236,293**	**$ 1,164,472**
41		NYPA - Peak	$ 443	$ 443	$ 441	$ 443	$ 441	$ 443	$ 2,654
42	(T)	NYPA - Peaking Transmission	$ 400	$ 400	$ 400	$ 400	$ 400	$ 400	$ 2,400
43	**Sub-total Peaking**		**$ 843**	**$ 843**	**$ 841**	**$ 843**	**$ 841**	**$ 843**	**$ 5,054**
44									
45		Service Billing	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	**$ 600**
46	(T)	**Hydro Quebec**	$ **1,200**	$ **1,200**	$ **1,200**	$ **1,200**	$ **1,200**	$ **1,200**	$ **7,200**
47		ENE All Requir/Supply	$ 6,580	$ 6,580	$ 6,580	$ 6,580	$ 6,580	$ 6,580	**$ 39,480**
48		ISO Annual Fee	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
49		ISO Load Based Charges	$ 13,418	$ 6,324	$ 2,765	$ 841	$ 5,509	$ 3,073	**$ 31,930**
50		ISO Scheduled Charges	$ 7,632	$ 6,290	$ 6,702	$ 5,809	$ 5,552	$ (3,443)	**$ 28,542**
51	(T)	**NEPOOL OATT Charge**	$ **87,032**	$ **107,589**	$ **92,879**	$ **79,436**	$ **69,863**	$ **76,777**	$ **513,576**
52	(T)	**Network Trans Service (NGRID)**	$ **21,500**	$ **21,500**	$ **21,500**	$ **21,500**	$ **21,500**	$ **21,500**	$ **129,000**
53	(T)	**DAF Charge (NGRID)**	$ **6,700**	$ **6,700**	$ **6,700**	$ **6,700**	$ **6,700**	$ **6,700**	$ **40,200**
54		Total (non-transmission)	$ 27,730	$ 19,294	$ 16,147	$ 13,330	$ 17,741	$ 6,310	$ 100,552
55		**Transmission (T) subtotal**	$ **116,432**	$ **136,989**	$ **122,279**	$ **108,836**	$ **99,263**	$ **106,177**	$ **689,976**
56		**Total**	**$ 144,162**	**$ 156,283**	**$ 138,426**	**$ 122,166**	**$ 117,004**	**$ 112,487**	**$ 790,528**
57									
58	Total	**All Transmission**	$ 134,901	$ 151,458	$ 132,748	$ 116,805	$ 105,732	$ 126,646	$ 768,290
59	Total	**Energy (Fixed and Variable)**	**$ 379,691**	**$ 316,954**	**$ 278,884**	**$ 262,677**	**$ 267,785**	**$ 339,497**	**$ 1,845,488**
60	Total	**Total Costs for Period**	**514,592**	**468,412**	**411,632**	**379,482**	**373,517**	**466,143**	**$ 2,613,778**
61									
62	*(1) Please See Energy New England Bulk Power Cost Projections, Schedule G*								
63									
64	*(2) The total for Seabrook (Project 6) includes the Surplus Fund Credit*								
65									

	A	B	C	D	E	F	G	H	I
66	*(T) Indicates Transmission*								**Schedule F-2**
67									
68									
69					**Pascoag Utility District**				
70					**Restated Forecast Purchased Power Costs**				
71									
72			**Jul 2014**	**Aug 2014**	**Sept 2014**	**Oct 2014**	**Nov 2014**	**Dec 2014**	**Period Total**
73	**Annual Identified MMWEC Cost (3)**		**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	
74	Monthly Assessment		$ 46,917	$ 46,917	$ 46,917	$ 46,917	$ 46,917	$ 46,917	$ 281,500
75	Less Cumulative Carry Over		($10,816)	($10,816)	($10,816)	($10,816)	($10,816)	($10,816)	$ (64,895)
76	**Restated Transition Cost**		**36,101**	**36,101**	**36,101**	**36,101**	**36,101**	**36,101**	**$ 216,605**
77									
78	Transmission								
79		Transmission	$ 134,901	$ 151,458	$ 132,748	$ 116,805	$ 105,732	$ 126,646	$ 768,290
80	Net Transmission		$ 134,901	$ 151,458	$ 132,748	$ 116,805	$ 105,732	$ 126,646	$ 768,290
81									
82	**Restated Costs (Dollars) - Standard Offer**								
83		NYPA Firm	$ 14,774	$ 14,774	$ 14,579	$ 14,774	$ 14,579	$ 14,774	$ 88,254
84		NYPA - Peak	$ 443	$ 443	$ 441	$ 443	$ 441	$ 443	$ 2,654
85		Miller Hydro	$ 5,447	$ 4,834	$ 3,896	$ 5,987	$ 7,851	$ 7,885	$ 35,900
86		NextEra RISE Purchase	$ 25,270	$ 25,294	$ 23,128	$ 23,727	$ 28,807	$ 42,650	$ 168,876
87		Capacity Market Sales	($10,030)	($10,030)	($10,030)	($10,030)	($10,030)	($10,030)	($60,180)
88		Dominion Capacity Purchases	$ 14,040	$ 14,040	$ 14,040	$ 14,040	$ 14,040	$ 14,040	$84,240
89		Spruce Mnt.	$ 9,014	$ 9,627	$ 12,359	$ 15,273	$ 15,880	$ 18,438	$ 80,591
90		REC Quarterly credit		$ (23,469)			$ (21,294)		$ (44,763)
91		ISO Energy Interchange	$ 56,751	$ 27,004	$ 21,026	$ 16,945	$ 29,662	$ 55,867	$ 207,255
92		Capacity Market Purchase	$ 31,249	$ 31,249	$ 31,249	$ 31,249	$ 31,249	$ 31,249	$ 187,494
93		Constellation Purchase	$ 109,847	$ 108,802	$ 59,972	$ 45,048	$ 47,190	$ 64,657	$435,516
94		Project 6 (total billing)	$ 81,677	$ 81,677	$ 81,424	$ 81,677	$ 81,424	$ 81,677	$489,556
95		Service Billing	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 600
96		Constellation Load Follow	$ 13,479	$ 13,415	$ 10,653	$ 10,214	$ 10,245	$ 11,537	$ 69,543
97		ISO Annual Fee	$ -	$ -	$ -	$ -	$ -	$ -	$ -
98		ISO Load Based Charges	$ 13,418	$ 6,324	$ 2,765	$ 841	$ 5,509	$ 3,073	$ 31,930
99		ISO Scheduled Charges	$ 7,632	$ 6,290	$ 6,702	$ 5,809	$ 5,552	$ (3,443)	$ 28,542
100		ENE Expenses	$ 6,580	$ 6,580	$ 6,580	$ 6,580	$ 6,580	$ 6,580	$ 39,480
101		**Sub-Total**	$ 379,691	$ 316,954	$ 278,884	$ 262,677	$ 267,785	$ 339,497	$ 1,845,488
102	Less Identified Project 6 Transition		$ (46,917)	$ (46,917)	$ (46,917)	$ (46,917)	$ (46,917)	$ (46,917)	($281,500)
103	**Restated Costs - Standard Offer**		**$ 332,774**	**$ 270,037**	**$ 231,967**	**$ 215,760**	**$ 220,868**	**$ 292,580**	**$ 1,563,988**
104									
105	**Restated Costs:**								
106	**Transition**		$ 46,917	$ 46,917	$ 46,917	$ 46,917	$ 46,917	$ 46,917	$ 281,500
107	**Transmission**		$ 134,901	$ 151,458	$ 132,748	$ 116,805	$ 105,732	$ 126,646	$ 768,290
108	**Standard Offer**		$ 332,774	$ 270,037	$ 231,967	$ 215,760	$ 220,868	$ 292,580	$ 1,563,988
109	**Total Restated Costs**		**$ 514,592**	**$ 468,412**	**$ 411,632**	**$ 379,482**	**$ 373,517**	**$ 466,143**	**$ 2,613,778**
110									
111			**Jul 2014**	**Aug 2014**	**Sept 2014**	**Oct 2014**	**Nov 2014**	**Dec 2014**	
112			**2 YR Average**	**2 YR Average**	**2 YR Average**	**2 YR Average**	**2 YR Average**	**2 YR Average**	
113	**Actual Sales Previous Period (4)**		4,855	5,648	5,266	4,072	4,350	4,645	28,837
114	**No Growth Factor**		49	56	53	41	44	46	288
115								-	-
116	**Estimated Sales (5)**		**4,904**	**5,705**	**5,319**	**4,113**	**4,394**	**4,691**	**29,125**
117									
118		Transition	$ 9.57	$ 8.22	$ 8.82	$ 11.41	$ 10.68	$ 10.00	$ 9.67
119		Transmission	$ 27.51	$ 26.55	$ 24.96	$ 28.40	$ 24.07	$ 27.00	$ 26.38
120		Standard Offer	$ 67.86	$ 47.33	$ 43.61	$ 52.46	$ 50.27	$ 62.37	$ 53.70
121		Total	**$ 104.94**	**$ 82.11**	**$ 77.39**	**$ 92.26**	**85.02**	**99.36**	**$ 89.74**
122									
123									
124	*(3)*	*From Pascoag's Audited Financial Statements, FY ending 12/31/2012; Contingent Liability - MMWEC Footnote, Page 22. For 2014, the*							
125		*total annual cost is $563,000*							
126									
127	*(4)*	*From Schedule E (two-year average)*							
128									
129	*(T)*	*Indicates Transmission Charges*							

RIPUC Docket No. 4454

Pascoag Utility District

Addendum Filing

Schedule H

	A	B	F	G	H
1					**Schedule H**
2					
3		**Forecast Rates**			
4					
5	**Transition Cost Calculations:**				
6	Estimated Sales (MWH) to customers		29,125		See Schedule F-2, Line 116
7					
8	Forecast Transition Cost		$216,605		See Schedule F-2, line 76
9	Historic Transistion Revenue		($190,482)		See Schedule A-3, Line 139
10	Historic Transition Expense		$ 281,500		See Schedule A-2, Line 74
11	Carry over from prior period (12/31/2013)		($129,790)		See Schedule C-3, Line 83
12		Total	$177,833		
13					
14	**Cost Per MWH**		**$ 6.11**		**Transition Charge**
15					
16	**Transmission Cost Calculations:**				
17	Estimated Sales (MWH) to customers		29,125		See Schedule F-2, Line 116
18					
19	Forecast Transmission Cost		$768,290		See Schedule F-2, line 80
20	Historic Transmission Revenue		($700,878)		See Schedule A-3, Line 141
21	Historic Transmission Expense		$ 994,838		See Schedule A-2, Line 80
22	Carry over from prior period (12/31/2013)		($213,954)		See Schedule C-4, Line 83
23		Total	$848,296		
24					
25	**Cost per MWH**		**$ 29.13**		**Transmission Charge**
26					
27	Standard Offer Calculation:				
28	Estimated Sales (MWH) to customers		29,125		See Schedule F-2, Line 116
29					
30	Forecast Standard Offer		$1,563,988		See Schedule F-2, line 103
31	Historic SOS Revenue		($1,825,489)		See Schedule A-3, Line 140
32	Historic SOS Expense		$ 1,789,774		See Schedule A-2, Line 107
33	Carry over from prior period (12/31/2013)		$724,966		See Schedule C-2, Line 85
34		Total	$2,253,239		
35					
36	**Cost per MWH**		**$ 77.36**		**Standard OfferService**
37					**$ 112.60**
38					
39	***(1) This is the net amount including any over/(under) recovery***				
40					
41					
42		**Revenue/Expense Proof:**			
43					
44	Forecast Transition Cost		$ 216,605		See Schedule F-2, line 76
45	Over/Under Collection at period end		$ (38,772)		Schedule C-3, Line 103
46			$ 177,833		$ 6.11
47					
48	Forecast Transmission Cost		$ 768,290		See Schedule F-2, line 80
49	Over/Under Collection at period end		$ 80,006		Schedule C-4, Line 102
50			$ 848,296		$ 29.13
51					
52	Forecast SOS Cost		$ 1,563,988		See Schedule F-2, line 103
53	Over/Under Collection at period end		$689,251		Schedule C-2, Line 105
54			$ 2,253,239		$ 77.36
55					
56					**$ 112.60**

Pascoag Utility District - Electric Department
Comparison of Current Rate vs. Proposed Rate
Impact on a 500 Kilowatt-hour Residential Customer

Column 1 Rate at Y/E 2013			Column 2 Rate Approved December 2013 for FY 2014				Column 3 Rate Based on Actual Purchase Power Expenses To-Date			
	Unit Cost	**Total**		**Unit Cost**	**Total**			**Unit Cost**	**Total**	
Customer Charge		$ 6.00	Customer Charge		$ 6.00		Customer Charge		$ 6.00	
Distribution	$ 0.03922	$ 19.61	Distribution	$ 0.03922	$ 19.61		Distribution	$ 0.03922	$ 19.61	
Transition	$ 0.01257	$ 6.28	Transition	$ 0.00568	$ 2.84	2013 Filing	Transition	$ 0.00611	$ 3.05	Schedule H, Line 14
Standard Offer	$ 0.03550	$ 17.75	Standard Offer	$ 0.07039	$ 35.20	2013 Filing	Standard Offer	$ 0.07736	$ 38.68	Schedule H, Line 36
Transmission	$ 0.02505	$ 12.54	Transmission	$ 0.02488	$ 12.44	2013 Filing	Transmission	$ 0.02913	$ 14.56	Schedule H, Line 25
DSM/Renewable	$ 0.00230	$ 1.15	DSM	$ 0.00230	$ 1.15		DSM	$ 0.00230	$ 1.15	
Total		$ 63.33	Total		$ 77.23		Total		$ 83.06	
			Net Increase/(Decrease)		$ 13.90		Net Increase/(Decrease)		$ 5.83	
			Percent Increase/(Decrease)		22%		Percent Increase/(Decrease)		7.6%	
Transition	$ 0.01257		Transition	$ 0.00568	$ (0.00689)	-55%	Transition	$ 0.00611	$ 0.00043	
SOS	$ 0.03550		SOS	$ 0.07039	$ 0.03489	98%	SOS	$ 0.07736	$ 0.00697	
Transmission	$ 0.02505		Transmission	$ 0.02488	$ (0.00017)	-1%	Transmission	$ 0.02913	$ 0.00425	
Total	$ 0.07312		Total	$ 0.10095	$ 0.02784	38.1%	Total	$ 0.11260	$ 0.01165	

Schedule H-1