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

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

RIPUC Docket No. 4529

Book 1 – Testimony and Testimony Exhibits

Michael R. Kirkwood, General Manager

Judith R. Allaire, Assistant General Manager

Testimony & Testimony Exhibits

Michael R. Kirkwood, General Manager

Q. Can you detail Pascoag's power portfolio for 2015?

A. M. Kirkwood Pascoag's power portfolio for 2015, used in developing this Standard Offer, Transition and Transmission rate reconciliation request, is detailed in *Table 1-MRK*, below:

Table 1-MRK

Pascoag Utility District 2015 Power Entitlements

NYPA	24%	(Hydro)
Miller Hydro	3%	(Hydro)
Spruce Mountain	3%	(Wind)
Seabrook	18%	(Nuclear)
NextEra RISE	10%	(virtual gas-fired)
TransCanada	42%	(mostly Fossil Fuel)
	100%	

The total renewable/sustainable power in this portfolio is 30%. This represents mostly hydro power (NYPA and Miller Hydro) at 27%, with one wind entitlement, Spruce Mountain, estimated to contribute 3% of the District's total annual purchased energy in 2015.

Pascoag's total non-carbon based energy is 48% of its requirements and includes a mix of the previously mentioned hydro and wind power, together with nuclear power from Pascoag's Seabrook entitlement. The remaining 52% of Pascoag's requirement is mainly fossil fuel based energy through a 3-year contract entered into with TransCanada Power Marketing LTD. ("TransCanada") which commences in 2015 and a virtual gas-fired unit transaction reached with NextEra Energy Power Marketing ("NextEra RISE") that began in June of 2013. *Testimony Exhibit 1-MRK* highlights this mix or resources in graphic form.

Q. Please provide an update on Pascoag's recent power purchase agreement entered into in order to hedge the remainder of Pascoag's requirement in 2015.

A. M. Kirkwood Based on the extreme spot market pricing experienced in New England during last winter's Polar Vortex, Pascoag has been 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 in our mid-year filing in Docket 4454, 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 natural 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 its power supply advisor, Energy New England, thought it would be best to protect Pascoag's remaining open position through that period. Since Pascoag's three tranches of load following entitlements with Exelon (previously Constellation) were all set to expire at the end of December 2014, this left Pascoag with an open, unhedged position of 42% of its energy requirements in 2015 and beyond as illustrated in *Table 1-MRK* above and *Exhibit 1-MRK* attached.

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

A. Yes, Pascoag and ENE 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 expiring 2012-2014 agreements with Exelon, except that we sought a 100% load-following hedge for the whole 2015-2017 term of the agreement due to the volatility in future spot-market pricing expected for the next three or more years.

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

A. Pascoag and ENE queried several power suppliers in early April 2014 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 last winter for the un-hedged portion or our portfolio, which oftentimes exceeded 25 cents/kWh on the spot market and at times hit 50 cents/kWh. Please see Exhibit MRK-2, which is a copy of the contract (called a Confirmation) with TransCanada.

Q. Has Pascoag done anything else that would improve its fiscal position and rate stability?

A. M. Kirkwood The District has extended the number of EEI Master Power Purchase and Sales Agreements it has in place. In 2014, Pascoag added EEI Master Agreements with PSEG Energy Resources and Trade LLC and Shell Energy North America (US) L.P. to supplement those it had with TransCanada, NextEra Energy, Exelon/Constellation Energy and Macquarie Energy. These documents improve Pascoag's position in contract negotiations by streamlining the negotiation process with those it has signed EEI Master Agreements with and by ensuring Pascoag's credit worthiness to potential new EEI Master partners. In fact, it was the use of EEI Master Agreements which allowed the competitive solicitations that resulted in the previous beneficial Load Following Energy deals with Exelon/Constellation and Shell Energy, and the forward-looking Load Following deal with TransCanada. These EEI Masters allow the parties to transact quickly based on market conditions at the time the transactions are priced.

An additional measure to improve Pascoag's fiscal position and rate stability occurred in 2013. Since Pascoag had not had a base rate change since 2004, Pascoag hired a cost-of-service consultant, B&E Consulting LLC, and pursuant to the resulting work product filed a rate change request with the Commission and Division in Docket 4341. Pascoag entered into a settlement agreement with the Division, which was approved by the Commission pursuant to Order No. 20977 with an effective date of February 1, 2013. This order allowed Pascoag to collect a total annual cost of service of $2,540,035 including funding of our Restricted Fund for Capital of $306,200 per year, greatly improving Pascoag's operational cash flow and ability to provide for its capital needs.

Because of the undercollection which was becoming extreme at the beginning of 2014 due to the above detailed rise in power and transmission costs and as further described in the testimony of Judith Allaire, Pascoag, under consultation with the Division, requested a mid-year filing and adjustment of its pass through rates in Docket 4454. The rate relief granted by the Commission has been crucial in allowing Pascoag to recover from the high winter power costs and once again get on stable financial footing. Pascoag is extremely grateful for the consideration and cooperation of both the Division and the Commission in this regard.

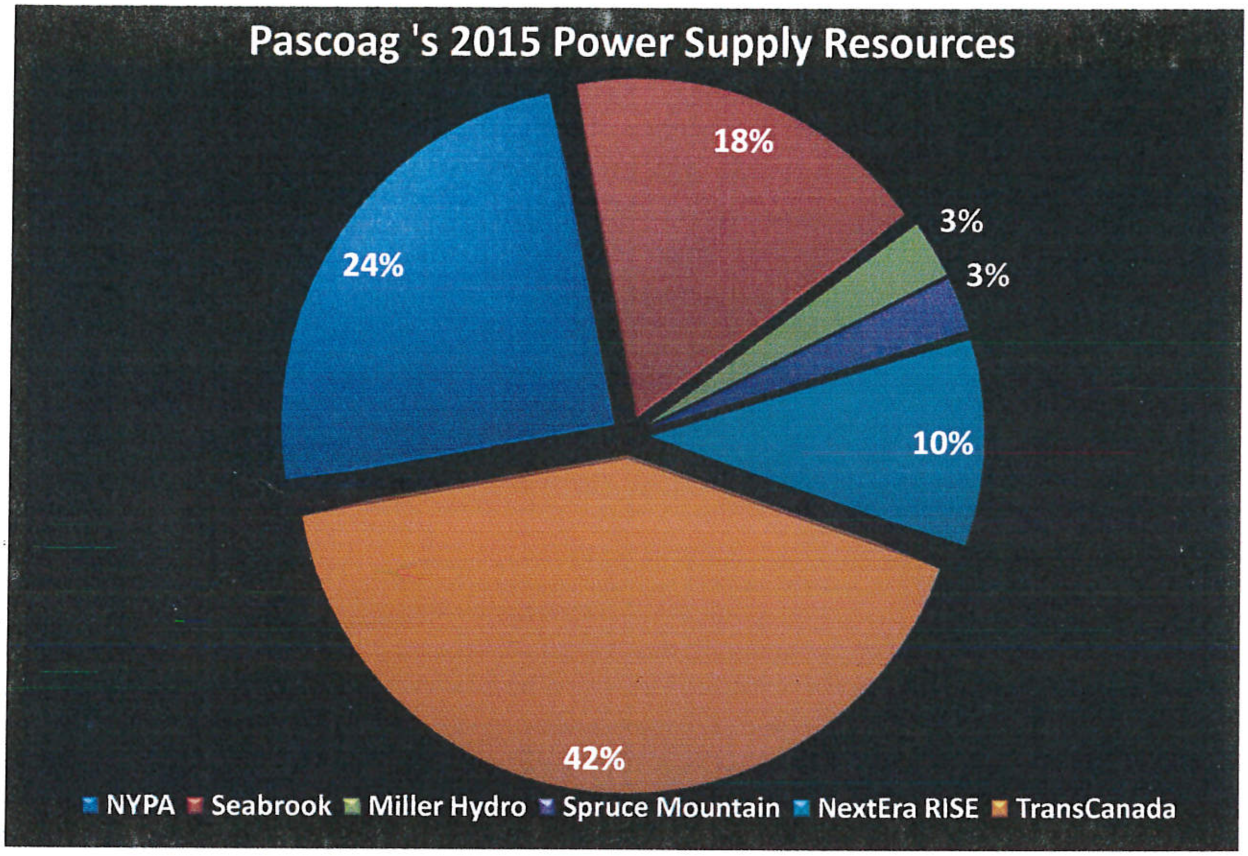
Finally by way of important information regarding Pascoag's fiscal health, Standard and Poor's re-affirmed the District's "A-"credit rating in 2014 based on the results of their annual review and rating of our company. Pascoag has now maintained an A- rating with S&P from 2008 to the present.

Q. Does this conclude your portion of the testimony?

A. M. Kirkwood

Yes it does.

Testimony Exhibit 1-MRK



Testimony Exhibit 2-MRK

Confirmation Letter for:

TransCanada Power Marketing, LTD.

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. <u>Definitions</u>. 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.	PASCOAG UTILITY DISTRICT, RHODE ISLAND
______________________	Michael R. Kirkwood
By:	By: Michael R. Kirkwood
Its:	Its: General Manager / CEO
______________________	
By:	
Its:	

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	GAS

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.

Testimony & Testimony Exhibits

Judith R. Allaire, Assistant General Manager

Q. Please provide an update on the status of Pascoag's fuel reconciliation for the period ending December 31, 2014.

A. As of the filing date (November 5, 2014), this submittal contains actual expenses and revenue through September 2014. The fourth quarter (October through December) is based on revised estimates provided by Energy New England ("ENE"). The projected reconciliation at December 31, 2014 is estimated to be an under collection of $293,399.

Q. What impact did the revisions for Quarter 4/Fiscal Year 2014 have on the original forecast? Please provide detail of the revisions.

A. The original forecast for 2014 was for $5,325,720[1]. The revisions for Quarter 4/FY 2014 added $156,284 to the original total, bringing the total revised 2014 forecast to $5,482,004 (***See Schedule D, Book 2***).

The budget assumptions used by ENE in the revisions for the fourth quarter are detailed in ***Testimony Exhibit JRA-1.***

Q. Please provide details of the under collection by factor, and explain how Pascoag was able to bring the over collection down from a high of $816,360 in March to this more manageable level.

A. On April 25, 2014, Pascoag filed for a mid-year rate adjustment to the Standard Offer Service, Transition Charge and Transmission Charge to mitigate a much larger under collection. At the time of the April filing, the forecast under collection through June 30th was $756,208.[2] A new rate, approved effective July 1, 2014, is beginning to show the benefit in the form of a much lower cumulative under collection than when Pascoag filed back in the spring. A summary of the cumulative over/ (under) collection is presented on Page 2, **Table 1**. The mid-year filing was an anomaly for Pascoag – historically the District files for a rate adjustment once a year in December. However, based on serious concerns of cash flow and the potential impact to customers if a mid-year correction was not made, PUD's management, after consultation with Division staff, made the decision that a mid-year correction would be in the best interest of both the District and its customers. Pascoag was appreciative of the support of both Commission and Division in implementing this much needed mid-year adjustment, and that by itself went a long way to improving PUD's fiscal position.

Prior to implementation of the mid-year rates, Pascoag used money from the Purchase Power Restricted Fund ("PPRF") to meet purchase power obligations. In total, over a two month period (January and February), the District withdrew $335,000 from the PPRF to pay higher than forecast expenses. A summary of the PPRF for 2014 is included as ***Testimony Exhibit JRA-2***. As indicated in this exhibit, PUD is beginning the process of reimbursement to the PPRF, and to-date $164,000 has been deposited back to the PPRF account.

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[1] Please see Prefiled Testimony, Judith R. Allaire, Page 5; RIPUC Docket No. 4454, Filing Date November 1, 2013.
[2] Please see Prefiled Testimony, Judith R Allaire, Page 1; RIPUC Docket No. 4454, Filing Date April 25, 2014

Table 1: Summary of Cumulative Combined Standard Offer, Transition Charge, and Transmission Charge

	Start Bal	Revenue	Expense	Monthly	Cumulative
Jan-13	$688,182	$465,175	$603,453	($138,278)	$549,903
Feb-13	$549,903	$459,212	$404,699	$54,513	$604,418
Mar-13	$604,418	$300,335	$504,762	($204,427)	$399,991
Apr-13	$399,991	$324,870	$372,310	($47,440)	$352,551
May-13	$352,551	$318,027	$398,061	($80,034)	$272,517
Jun-13	$272,517	$306,601	$427,313	($120,711)	$151,805
Jul-13	$151,805	$367,490	$509,357	($141,867)	$9,939
Aug-13	$9,939	$440,577	$410,149	$30,429	$40,367
Sep-13	$40,367	$352,227	$389,621	($37,394)	$2,974
Oct-13	$2,974	$309,332	$366,543	($57,211)	($54,237)
Nov-13	($54,237)	$332,189	$430,078	($97,889)	($152,126)
Dec-13	($152,126)	$332,370	$561,464	($229,094)	($381,220)
	Period Cumulative Over/(Under) collection			($1,069,404)	
Forecast Cumulative Over/(Under) Collection at 12/31/2013					($381,220)

Combined Standard Offer, Transition Charge, and Transmission Charge

	Start Bal	Revenue	Expense	Monthly	Cumulative	
Jan-14	($381,220)	$442,825	$ 661,586	($218,760)	($599,981)	
14-Feb	($599,981)	$530,192	$ 636,579	($106,386)	($706,367)	
Mar-14	($706,367)	$450,774	$ 560,767	($109,992)	($816,360)	
14-Apr	($816,360)	$444,044	$ 403,924	$40,119	($776,240)	
May-14	($776,240)	$434,867	$ 369,923	$64,944	($711,297)	
14-Jun	($711,297)	$420,373	$ 418,069	$2,304	($708,993)	
Jul-14	($708,993)	$479,707	$ 431,537	$48,169	($660,823)	
14-Aug	($660,823)	$607,443	$ 443,989	$163,453	($497,370)	
Sep-14	($497,370)	$536,547	$ 428,509	$108,039	($389,331)	
14-Oct	($389,331)	$458,534	$ 395,206	$63,328	($326,004)	**ESTIMATE**
Nov-14	($326,004)	$489,814	$ 392,104	$97,710	($228,294)	**ESTIMATE**
14-Dec	($228,294)	$523,011	$ 588,116	($65,105)	($293,399)	**ESTIMATE**
	Period Cumulative Over/(Under) collection			$87,822		
Forecast Cumulative Over/(Under) Collection at 12/31/2014					**($293,399)**	

Additionally, Pascoag has transferred a monthly amount to the PPRF equal to the base rate revenue (customer charge and demand charge) from Daniele Prosciutto International ("DPI") This monthly transfer of base rate revenue is a requirement from Pascoag's Cost of Service Case in 2013 (RIPUC Docket #4341).

The primary reasons for such high purchase power invoices in the first quarter of 2014 were due to the high natural gas prices over the winter period, the extreme winter weather, and large increases in the transmission costs associated with Pascoag's NYPA power.

In addition, for the first quarter of the year, Pascoag received only 612,000 interruptible kilowatt-hours from the two NYPA entitlements. As a point of reference, for the second quarter of the year, delivered interruptible kilowatt-hours went up to 1,673,000 kilowatt-hours; and delivered interruptible kilowatt-hours for the third quarter were 2,051,000 kilowatt-hours. In the first quarter of the year, the high transmission costs associated with delivery of NYPA power resulted in an average cost of slightly over eight cents per kilowatt-hour. By comparison, NYPA costs for September averaged under two cents per kilowatt-hour.

The forecast under collection at year-end 2014, by factor, is outlined in **Table 2**, below:

Table 2:	**Summary of Year-End Cumulative Over/(Under) Collection as of 12/31/2014)[3]**
Standard Offer Service	($161,778)
Transition	($73,666)
Transmission	($57,955)
Total	**($293,399)**

Q. What is the forecast for purchase power costs for 2015?

A. Pascoag, working with its consultants at ENE, has submitted the 2015 forecast for a total of $5,867,488, an increase of $541,768 over 2014's original forecast. **Table 3**, below, provides a summary:

[3] Based on actual expenses/revenue through September. Estimates have been used for October, November and December.

Table 3: ENE Forecast	2014 (Original)	2015	Difference
Energy	$3,773,983	$4,129,549	$355,566
Transmission	$1,551,737	$1,737,939	$186,202
Total	$5,325,720	$5,867,488	$541,768

ENE provided a summary sheet of the 2015 budget assumptions that is included as ***Testimony Exhibit JRA-3.***

An additional item that impacted the 2015 forecast is the assumption that DPI will begin the phase-out of its operations in Pascoag beginning in July 2015. Based on discussions with DPI management, Pascoag is forecasting a 10% reduction in DPI sales for July, and increasing by 10% each month for the remainder of 2015.

Q. In the mid-year filing, Pascoag detailed serious concerns with cash flow issues. Please provide an update on Pascoag's financial status.

A. The financial picture for Pascoag is much improved, thanks in large part to the mid-year rate increase. The increase in revenue allowed Pascoag to begin the process of reimbursement to the PPRF (see ***Testimony Exhibit JRA-2***).

Another concern discussed in the mid-year filing was the inability to meet funding requirements for the Restricted Fund for Capital and Debt Service. That fund, with an annual funding requirement set at $306,000, allows Pascoag to meet capital projects without assuming debt service. PUD tries to "level fund" this on a monthly basis (approximately $25,500 per month), but back in the late winter/early spring, we were well below that goal. Over the past several months, the District has been able to bring the monthly funding current. As of this filing, Pascoag has funded the account a total of $272,500, or 89% of the total requirement. Based on the anticipated monthly contribution for November and December, the District fully intends to successfully meet the annual funding requirement. A summary of activity to the Restricted Fund for Capital and Debt Service is attached as ***Testimony Exhibit JRA-4.***

Another item identified by Pascoag in the mid-year filing was concern that the District was having some difficulty meeting its financial obligations to non-power vendors. As of this date, the open Account Payable balance is all within the thirty-day window that is typical for Pascoag. A summary of the Account Payable/Account Receivable balances is attached as ***Testimony Exhibit JRA-5.***

As Mr. Kirkwood stated in his testimony, Standard and Poors have reaffirmed Pascoag's A-rating.

Cash flow summaries, attached as ***Testimony Exhibit JRA-6***, reflect the improvement in Pascoag's financial position over the past quarter. As of this filing, Pascoag's financial obligations are all current, funding to the Restricted Fund is on track, and the process of reimbursement to the PPRF has begun. So, a much improved view from what was discussed in the mid-year filing.

Q. Earlier in your testimony, you stated that the forecast used in this filing contained actual expenses and revenue through September and that estimates were used for October, November and December. Will you be able to provide an update on the actual expense at, or prior to, the hearing?

A. Yes. All of the October power invoices should be received by November 30, 2014, so Pascoag will be able to provide actual October expenses and revenue shortly after that date. The District will provide an addendum to this filing incorporating that information.

When November and December invoices are received and recorded, Pascoag will provide this information to the Division in its required monthly updates.

Q. What are the proposed factors, and what impact will they have on a residential customer using 500 kilowatt-hours of electricity?

A. A residential customer using 500 kilowatt-hour of electricity currently pays $83.06. Under the proposed rates, that customer would see his monthly bill increase to $83.08, an increase of $0.02. This filing is actually more of a realignment among the factors, rather than a rate increase. A detailed summary of current rates and requested rates is included in this filing as ***Testimony Exhibit JRA-7.*** The proposed factors are listed in **Table 4:**

Table 4: **Factor**	**Current**	**Proposed**	**Difference**
Standard Offer	$0.07736	$0.06835	($0.00901)
Transition	$0.00611	$0.01146	$0.00535
Transmission	$0.02913	$0.03283	$0.00370
Total	$0.11260	$0.11264	$0.00040

Q. Is Pascoag using any growth factor in its calculations for 2015?

A. The District is beginning to see some residential projects that have been in developmental stages start to emerge and become active construction projects. Based on this, and what seems to be an improving economy, Pascoag is forecasting a one percent growth factor in this filing.

Q. Are there any other issues that impact Pascoag's financial position?

A. As in past years, we continue to see relatively high annual write offs. This year, the estimated uncollectable accounts is approximately $30,000. Part of the reason for this is that the District is encountering some difficulties with collection on protected status customers. These problems are outlined more fully in the District's monthly reports in RIPUC No. 1725. **Table 5** is a history of the District's uncollectable accounts from 2009 to 2014.

Table 5: History of District Write Offs	
2009	$30,222
2010	$19,588[4]
2011	$31,355
2012	$36,083
2013	$31,777
2014 (Estimate)	$30,000

Q. Are there any other issues that impact Pascoag?

A. This year has been a year of change for the staff at Pascoag Utility District. We are transitioning from our legacy computer software to a new, fully integrated software package. The first half of the year saw the complete implementation of the accounting portion of the software (general ledger, accounts payable, fixed asset management, miscellaneous receivables, payroll, purchase orders, inventory, and fleet management)

We are now nearing completion on the customer care portion of the software. In addition to utility billing, this includes many new features such as outage management, "call capture" (which allows our customers access to automated account information, including real-time payment, twenty-four hours a day, seven days a week, using a toll-free number), a new, improved on-line bill presentation format, and a mapping and graphical interface that will track meters, transformers and other equipment on our distribution system.

[4] Pascoag's financial hardship customers were eligible for an ARRA grant, administered through Tri-Town, which was applied directly to past due electric accounts. This resulted in the lower than average write offs for 2010.

The new software company, National Information Software Cooperative ("NISC"), is an information technology company that develops and supports software and hardware solutions for its members/owners. Most of the members are utility cooperatives and telecommunication companies, providing service to more than five million consumers in 48 states and Canada. NISC provides advanced, integrated IT solutions for customer care and billing, accounting, engineering, and operation applications. NISC maintains offices in four states including Missouri, North Dakota, Wisconsin, and Iowa.

As a cooperative, NISC is owned by users of its software. This translates to a deep working knowledge of the utility industry and operations, as well as regulatory requirements.

Q. As part of the Report and Order in RIPUC Docket No. 4341 (Pascoag's Cost of Service Rate Case), Pascoag was ordered to provide quarterly reports to Commission and Division staff. Has Pascoag met this requirement?

A. Yes, Pascoag has provided the quarterly reports to Commission and Division staff in March, June and September. The final report for 2014 will be submitted in December. All requirements of the Report and Order pertaining to funding of the Restricted Fund and Storm Fund have been met.

Q. Does this conclude your testimony?

A. Yes, it does.

Testimony Exhibits

Of

Judith R. Allaire

Testimony Exhibit JRA – 1

ENE Budget Assumptions – Quarter 4/FY 2014

Testimony Exhibit JRA-1

Provided By ENE

4Th Quarter Revision Budget Assumptions

MWH			Total Costs		$/MWH
14,077		2014 Original Budget	$ 1,219,142	$	86.60
14,077		2014 Revised Budget	$ 1,375,426	$	97.71
-		Total Increase (+) /Decrease (-) of	$ 156,285	$	(11.10)

Details of Increase:

			Adj:	Total Adj of :
1	Adjustments to NYPA Expenses			
	Demand Rate	Rate Modification Plan -prelimary staff report 7/11	$ 690	
	Transmission	46% Increase based on last year's actual costs, due to the congestion during	$ 10,000	
		Total NYPA Adjustments		$ 10,690
2	Adjustments to Seabrook Costs			
		Adjusted Fixed Cost rate from $60 to $56.85/kw-mo	$ 23,422	
		Removed the Flush of funds of $6,000/mo	$ (18,000)	
		Adjusted the Energy Price	$ (924)	
		Total Seabrook Adjustments		$ 4,498
3	Adjustments to ENE's Fee from $6,580/mo to $6,7850/mo			$ 615
	Updated estimatd pricing for NextEra Rise Call Option for 4th quarter based on Current Gas Market Pricing			$ 20,005
5	Updated the estimated pricing for the purchases from the ISO-NE for Power			$ 28,872
6	Adjustments to Estimated ISO Expenses			
		Annual Fee		
		Load Based Charges	$ 70,282	
		Scheduled Charges	$ 13,284	
		Total ISO Expense Adjustments		$ 83,566
##	Adjusted OATT RNS Rate to $7.43/kw-mo for Oct-Dec			$ (9,749)
##	Updated NGRID Network Transmission Charges, based on historical averages from $21,500/mo to $27,750/mo			$ 18,750
##	Increase DAF Charges			
	Oct-Dec	from $6,700/mo to $6,379/mo		$ (963)

Total Adjustment $ 156,285

Variance $ -

Testimony Exhibit JRA – 2

Purchase Power Restricted Fund

Pascoag Utility District
Restricted Fund Account
RIPUC Docket No. 4341 - Cost of Service Settlement Agreement - Purchase Power
Year Ending December 31, 2014

Date	Beginning	Interest	Deposits	Withdrawals	Balance	Notes
12/31/2013	$ 497,982.60				$ 497,982.60	
1/16/2014			$ 18,230.00		$ 516,212.60	DPI Base Rate transfer - January
1/16/2014				$ (180,000.00)	$ 336,212.60	low cash flow, high power bills
2/19/2014				$ (155,000.00)	$ 181,212.60	low cash flow, high power bills
2/25/2014			$ 18,230.00		$ 199,442.60	DPI Base Rate transfer - February
3/26/2014			$ 18,230.00		$ 217,672.60	DPI Base Rate transfer - March
4/22/2014			$ 18,230.00		$ 235,902.60	DPI Base Rate transfer - April
5/21/2014			$ 18,230.00		$ 254,132.60	DPI Base Rate transfer - May
6/20/2014			$ 18,230.00		$ 272,362.60	DPI Base Rate transfer - June
7/15/2014			$ 18,230.00		$ 290,592.60	DPI Base Rate transfer - July
7/30/2014			$ 63,968.00		$ 354,560.60	MMWEC Surplus Fund Annual Credit
8/25/2014			$ 17,443.00		$ 372,003.60	DPI Base Rate transfer - August
8/25/2014			$ 30,000.00		$ 402,003.60	Reimbursement to PPRF
9/22/2014			$ 17,698.00		$ 419,701.60	DPI Base Rate transfer - Sept
9/22/2014			$ 30,000.00		$ 449,701.60	Reimbursement to PPRF
10/20/2014			$ 40,032.00		$ 489,733.60	Reimbursement to PPRF
10/20/2014			$ 17,476.00		$ 507,209.60	DPI Base Rate transfer - Oct
Totals	$ 497,982.60	0	$ 344,227	$ (335,000)	$ 507,209.60	

Summary of 2014 Withdrawals:

1/1/2014	$ (180,000)
2/14/2014	$ (155,000)
	$ (335,000)

Summary of 2014 Reimbursements:

7/30/2014	$ 63,968	MMWEC Surplus Fund Credit
8/25/2014	$ 30,000	August reimbursement
9/22/2014	$ 30,000	Sept reimbursement
10/20/2014	$ 40,032	Oct reimbursement
	$ 164,000	

Testimony Exhibit JRA-2

Testimony Exhibit JRA – 3

ENE 2015 Budget Assumptions

2015 Budget Assumptions

Provided By ENE

MWH
57,771
57,665
(106)

	Total Costs	$/MWH
2014 Budget	$ 5,325,720	$ 92.19
2015 Budget	$ 5,867,488	$ 101.75
Total Increase (+) /Decrease (-) of	$ 541,768	$ (9.56)

Details of Increase:

	Adj:	Total Adj of :
1 Seabrook Projections - Updated to reflect 3/26/14 Budget		
Fixed Cost - reduced from $60/kw to $56.06/kw, removed of Surplus Fund credit	$ (3,802)	
Energy - reduced to $7.71/MWH from $8.21/MWH for Jan-Sep, reduced to $7.53/MWH from $8.03/MWH for Oct-Dec , Outage in October	$ (4,223)	
Transmission - increased based on projections	$ 408	$ (7,617)
2 NYPA Projections based on historical deliveries and costs		
Fixed Costs - increased from $3.97/kw to $4.07/kw	$ 3,864	
Energy - no pricing change capacity kept at 75%	$ -	
Transmission - congestion based on actuals with a 2.5% increase	$ 165,500	$ 169,364
3 Capacity - Updated Projection to reflect auction pricing, bilaterals, and payments by LP		
FCM Payments by LP	$ 68,266	
ISO FCM Costs	$ 5,838	
FCM Bilateral Costs*	$ (62,070)	$ 12,034
4 Updated NextEra Rise Call Option		
Fixed Cost - Applied Capacity cost against ISO credit in item#3	$ (32,670)	
Energy - Update prices based on Current Market Pricing	$ 111,659	$ 78,989
5 Bilateral Transactions		
Energy - Miller Hydro - update projects based on historical deliveries	$ 6,312	
Energy - Spruce Mtn - update projects based on historical deliveries includes placeholder for REC Sales	$ (30,941)	
Energy - TransCanada 100% LF less Fixed Volumes	$ 767,036	$ 742,407
6 Change from resales to purchases from the ISO-NE for Power		$ (584,106)
7 ENE All Req/Short Supply		
Estimated increase from $6,785/mo to $6,850/mo		$ 3,240
8 Adjustments to Estimated ISO Expenses		
Annual Fee	$ -	
Load Based Charges to account for Winter Reliability	$ 88,808	
Scheduled Charges	$ 18,354	
Transmission Increase effective 6/1/14 & 6/1/15	$ 8,295	$ 115,457
9 NGRID Network Transmission Charges		
Jan - Mar Increase based on historical invoices		$ 12,000

Total Adjustment	**$ 541,768**
Variance	$ -

Testimony Exhibit JRA – 4

Restricted Fund – Capital and Debt Service

Testimony Exhibit JRA-4

Pascoag Utility District
Restricted Fund Account
RIPUC Docket No 4341
Year Ending December 31, 2014

Date	Beginning	Interest	Deposits	Withdrawals	Balance	Notes
	Annual Deposit Required:		$ 306,000.00			
12/31/2013	$ 491,213.50				$ 491,213.50	
1/7/2014				$ (33,045.00)	$ 458,168.50	(S/L, poles, insulators)
1/27/2014				$ (42,991.00)	$ 415,177.50	(NISC payment #1)
1/31/2014			$ 15,000.00		$ 430,177.50	
2/27/2014			$ 10,000.00		$ 440,177.50	
2/27/2014				$ (7,679.00)	$ 432,498.50	VOIP - Part of NISC Project
3/24/2014			$ 20,000.00		$ 452,498.50	
3/24/2014				$ (4,154.00)	$ 448,344.50	2 workstations; VOIP Project
4/28/2014			$ 20,000.00		$ 468,344.50	
5/28/2014			$ 30,000.00		$ 498,344.50	
5/28/2014				$ (11,386.00)	$ 486,958.50	NISC Project/Wesco data box-substation
6/5/2014				$ (15,000.00)	$ 471,958.50	AMR Meters (Phase 1)
6/20/2014			$ 40,000.00		$ 511,958.50	
7/21/2014			$ 45,000.00		$ 556,958.50	
7/21/2014				$ (14,609.00)	$ 542,349.50	(NISC project $6803 & AMR project $7806)
8/20/2014			$ 40,000.00		$ 582,349.50	
8/20/2014				$ (4,536.00)	$ 577,813.50	
9/18/2014			$ 27,500.00		$ 605,313.50	
10/15/2014			$ 25,000.00		$ 630,313.50	
10/15/2014				$ (20,471.00)	$ 609,842.50	(meters, street lights, truck lift & equipment)
	$ 491,213.50	0	$ 272,500	$ (153,871.00)	$ 609,842.50	

Restricted Account - Funding 2014

Annual Requirement		$ 306,000		
	Period Contribution	Year-to-date Funded	Percent Funded	Percent Goal
3/31/14	$ 45,000	$ 45,000	15%	25%
6/30/14	$ 90,000	$ 135,000	44%	50%
9/30/14	$ 112,500	$ 247,500	81%	75%
12/31/14	$ 25,000	$ 272,500	89%	100%
Y-T-D	$ 272,500			

Testimony Exhibit JRA – 5

AR/AP Summary

Summary of Accounts Payable (1)

	1 - 30 Days	31 - 60 Days	61 - 90 Days	Over 90 Days	Balance
June 09	$ 18,199				$ 18,199
July 09	$ 6,518				$ 6,518
Aug 09	$ -				$ -
Sept 09	$ 49,415				$ 49,415
Oct 09	$ 6,312				$ 6,312
Nov 09	$ 5,337				$ 5,337
Jan 10	$ 9,116				$ 9,116
Feb 10	$ 39,077				$ 39,077
Mar 10	$ 28,985				$ 28,985
April 10	$ 38,946				$ 38,946
May 10	$ 40,566				$ 40,566
June 10	$ 42,652				$ 42,652
July 10	$ 33,594				$ 33,594
Aug 10	$ 7,249				$ 7,249
Sept 10	$ 7,660				$ 7,660
Oct 10	$ 19,673				$ 19,673
Nov 10	$ 12,223				$ 12,223
Dec 10	$ 2,980				$ 2,980
Jan 11	$ 88,951	$ 19,858			$ 108,809
Feb 11	$ 44,864	$ 13,321			$ 58,185
Mar 11	$ 53,446				$ 53,446
Apr 11	$ 16,400				$ 16,400
May 11	$ 44,575	$ 19,206	$ 9,211		$ 72,992
Jun 11	$ 40,464	$ 5,427			$ 45,891
Jul 11	$ 19,194				$ 19,194
Aug 11	$ 34,438				$ 34,438
Sept 11	$ 18,850				$ 18,850
Oct 11	$ 6,860				$ 6,860
Nov 11	$ 34,014	$ 3,699			$ 37,713
Dec 2011	$ 12,911				$ 12,911
Jan 2012	$ 3,479				$ 3,479
Feb 2012	$ 115				$ 115
March 2012	$ 14,561				$ 14,561
April 2012	$ 12,434				$ 12,434
May 2012	$ 32,972				$ 32,972
June 2012	$ 5,337				$ 5,337
July 2012	$ 2,724				$ 2,724
August 2012	$ 11,392				$ 11,392
September 2012	$ 16,890				$ 16,890
October 2012	$ 6,683				$ 6,683
November 2012	$ 14,999				$ 14,999
December 2012	$ 5,618				$ 5,618
January 2013	$ 8,272				$ 8,272
February 2013	$ 2,588				$ 2,588
March 2013	$ 245				$ 245
April 2013	$ 350				$ 350
May 2013	$ -				$ -
June 2013	$ 10,184				$ 10,184
July 2013	$ 9,697				$ 9,697
August 2013	$ 31,792				$ 31,792
September 2013	$ 5,222				$ 5,222
October 2013	$ 1,219				$ 1,219
November 2013	$ 4,590				$ 4,590
December 2013	$ 7,517	$ 7,238	$ 5,728		$ 20,483
January 2014	$ 9,277				$ 9,277
February 2014	$ 1,596	$ 8,823			$ 10,419
March 2014	$ 11,974	$ 12,243	$ 16,895		$ 41,112
April 2014	$ 5,594	$ 18,637			$ 24,231
May 2014	$ 52,565				$ 52,565
June 2014	$ 24,198				$ 24,198
July 2014	$ 47,467				$ 47,467
August 2014	$ 42,983				$ 42,983
Sept 2014	$ 15,616				$ 15,616
Oct 2014					$ -
Nov 2014					$ -
Dec 2014					$ -

(1) As of the end of the month, not the end of the accounting period

Summary of Accounts Receivable

	1 - 30 Days	31 - 60 Days	61 - 90 Days	Over 90 Days	Balance	
June 09	$ 242,255	$ 61,515	$ 16,289	$ 47,399	$ 367,458	
July 09	$ 284,717	$ 49,015	$ 12,258	$ 47,597	$ 393,587	
Aug 09	$ 397,771	$ 72,486	$ 11,777	$ 46,798	$ 528,832	
Sept 09	$ 358,999	$ 94,893	$ 11,750	$ 47,856	$ 513,498	
Oct 09	$ 288,295	$ 79,502	$ 16,073	$ 47,519	$ 431,389	
Nov 09	$ 298,750	$ 78,208	$ 31,682	$ 54,115	$ 462,755	
Dec 09	$ 259,706	$ 73,488	$ 30,139	$ 31,840	$ 395,173	w/o $30,222
Jan 10	$ 406,987	$ 77,764	$ 31,382	$ 38,031	$ 554,164	
Feb 10	$ 374,265	$ 87,974	$ 33,458	$ 43,331	$ 539,028	
March 10	$ 274,339	$ 84,436	$ 35,289	$ 39,670	$ 433,734	
April 10	$ 317,238	$ 64,922	$ 25,397	$ 38,791	$ 446,348	
May 10	$ 259,596	$ 82,240	$ 18,480	$ 41,226	$ 401,542	
June 10	$ 296,754	$ 51,456	$ 16,868	$ 40,647	$ 405,725	
July 10	$ 634,367	$ 82,326	$ 17,598	$ 40,628	$ 774,919	
Aug 10	$ 414,040	$ 91,728	$ 15,014	$ 41,549	$ 562,331	
Sept 10	$ 367,844	$ 108,647	$ 20,746	$ 42,024	$ 539,261	
Oct 10	$ 333,354	$ 104,968	$ 18,835	$ 39,190	$ 496,347	
Nov 10	$ 262,288	$ 91,484	$ 35,340	$ 25,418	$ 414,530	ARRA grants
Dec 10	$ 375,702	$ 77,928	$ 37,338	$ 37,649	$ 528,617	w/o $19,588
Jan 11	$ 450,388	$ 100,876	$ 31,926	$ 47,450	$ 630,640	
Feb 11	$ 448,389	$ 131,298	$ 39,578	$ 51,404	$ 670,669	
Mar 11	$ 304,438	$ 111,482	$ 38,110	$ 49,255	$ 503,285	
Apr 11	$ 345,832	$ 94,256	$ 40,915	$ 51,256	$ 532,259	
May 11	$ 300,380	$ 110,420	$ 27,838	$ 50,626	$ 489,264	
Jun 11	$ 276,381	$ 71,421	$ 21,131	$ 49,402	$ 418,335	
Jul 11	$ 357,351	$ 67,649	$ 14,772	$ 52,356	$ 492,128	
Aug 11	$ 416,316	$ 102,619	$ 13,487	$ 52,552	$ 584,974	
Sept 11	$ 426,478	$ 104,613	$ 19,024	$ 53,944	$ 604,059	
Oct 11	$ 277,270	$ 115,253	$ 19,070	$ 55,117	$ 466,710	
Nov 11	$ 279,731	$ 81,547	$ 39,877	$ 62,836	$ 463,991	
Dec 11	$ 310,415	$ 80,636	$ 31,743	$ 45,586	$ 468,380	w/o $31,355
Jan 12	$ 357,987	$ 80,400	$ 33,331	$ 49,753	$ 521,471	
Feb 12	$ 287,214	$ 100,680	$ 31,835	$ 52,032	$ 471,761	
March 2012	$ 262,535	$ 81,095	$ 36,962	$ 50,863	$ 431,455	
April 2012	$ 270,258	$ 84,771	$ 31,753	$ 56,978	$ 443,760	
May 2012	$ 243,911	$ 69,904	$ 22,454	$ 55,862	$ 392,131	
June 2012	$ 273,935	$ 51,677	$ 21,763	$ 57,536	$ 404,911	
July 2012	$ 322,261	$ 62,174	$ 12,657	$ 57,456	$ 454,548	
August 2012	$ 389,238	$ 77,173	$ 13,826	$ 57,775	$ 538,012	
September 2012	$ 450,684	$ 98,213	$ 13,308	$ 58,471	$ 620,676	
October 2012	$ 227,297	$ 110,469	$ 15,766	$ 21,373	$ 374,905	w/o $36,083
November 2012	$ 304,511	$ 59,474	$ 36,017	$ 25,943	$ 425,945	
December 2012	$ 458,273	$ 60,113	$ 26,149	$ 40,248	$ 584,783	
January 2013	$ 329,564	$ 85,844	$ 32,713	$ 43,531	$ 491,652	
February 2013	$ 383,060	$ 101,903	$ 35,440	$ 46,106	$ 566,509	
March 2013	$ 290,317	$ 85,366	$ 28,677	$ 50,131	$ 454,491	
April 2013	$ 259,318	$ 67,822	$ 33,749	$ 48,731	$ 409,620	
May 2013	$ 228,552	$ 68,929	$ 22,080	$ 45,870	$ 365,431	
June 2013	$ 288,616	$ 64,757	$ 19,800	$ 48,036	$ 421,209	
July 2013	$ 287,141	$ 53,393	$ 16,822	$ 47,458	$ 404,814	
August 2013	$ 340,709	$ 65,483	$ 12,813	$ 46,749	$ 465,754	
September 2013	$ 289,175	$ 72,977	$ 15,023	$ 45,583	$ 422,758	
October 2013	$ 225,915	$ 60,602	$ 17,463	$ 44,486	$ 348,466	
November 2013	$ 369,027	$ 56,777	$ 26,592	$ 23,873	$ 476,269	w/o $31,777
December 2013	$ 279,105	$ 78,898	$ 25,738	$ 34,618	$ 418,359	
January 2014	$ 395,468	$ 71,815	$ 31,516	$ 40,198	$ 538,997	
February 2014	$ 472,925	$ 117,649	$ 32,657	$ 45,558	$ 668,789	
March 2014	$ 318,299	$ 114,973	$ 43,391	$ 45,123	$ 521,786	
April 2014	$ 328,138	$ 88,477	$ 44,477	$ 46,310	$ 507,402	
May 2014	$ 284,669	$ 86,838	$ 33,958	$ 54,232	$ 459,697	
June 2014	$ 298,111	$ 74,194	$ 30,695	$ 58,030	$ 461,030	
July 2014	$ 380,523	$ 62,169	$ 22,280	$ 63,457	$ 528,429	
August 2014	$ 462,507	$ 92,298	$ 17,761	$ 64,652	$ 637,218	
Sept 2014	$ 410,525	$ 110,602	$ 23,333	$ 66,424	$ 610,884	
Oct 2014						
Nov 2014						
Dec 2014						

Testimony Exhibit JRA – 6

Cash Flow Summary

Testimony Exhibit JRA-6

Summary of Cash Flow - January 2014

Operating Cash balance forward	$ 172,415		
Projected Purchased Power Expenes:			
ENE	($204,503)		
·oject 6 (MMWEC & HQ)	($83,660)		
NYPA	($38,551)		
ENE/ISO	($194,915)		
		($521,629)	
Customer Payments	$ 645,719		
NSF cks	$0		
Payroll, benefits	($126,070)		
Transfer from RF	$33,045		(capital - S/L, poles, insulators)
Transfer from RF	$42,911		(Capital - NISC, payment #1)
Transfer to RF	($15,000)		January partial contribution
Transfer from PPRF	$180,000		high power bills, low cash flow (See Summary, below)
Transfer to PPRF	($18,230)		(DPI Base rate - January)
NISC Payment	($42,911)		
Misc. vendor payments	($174,119)		
encumber for additional insurance	($7,000)		
Annual Assessment - RIDPU	($34,197)		
Annual Insurance Prem	($29,078)		(partial)
Encumber for PP - from Jan	$235,000		
Encumber for PP - for Feb	($200,000)		
	$140,856		

Other Financial Information:

Accounts Payable Balance	$ 9,277
Accounts Receivable Balance	$ 538,997

Summary of Savings/Investments: (Not Restricted)

Contingency/Emergency	$ 10,000
Storm Fund	$ 19,169
Working Cash Reserve	$ 60,372
Dedicated DSM Fund	
Total Savings/Investment (NR)	$ 89,541

Year-End Reconciliation Account	**$ 5,700**	
Restricted Account(Debt/Capital)	**$ 430,177**	
Restricted Account (RSF)	**$ -**	
Restricted Account(Purchase Pwr)	**$ 336,212**	
Net All Saving/Investment		**$ 861,630**

Summary of PPRF Transfer:

Power Bills Due	$521,629	
Encumbered as of 1/16	$ (340,000)	
	$181,629	(rounded to $180,000)

Misc. Accounts:

Customer Deposit Holding Account	$ 256,870
Working Capital - on Deposit w/ ENE	$ 169,288
Working Capital - on Deposit w/MMWE	$ 2,232

Restricted Fund 2014 **$ 306,000**

Jan-14	$ 15,000
Feb-14	
Mar-14	
Apr-14	
May-14	
Jun-14	
Jul-14	
Aug-14	
Sep-14	
Oct-14	
Nov-14	
Dec-14	$ -
Total Transfer	**$ 15,000**

Annual Funding Level	% Complete	Funding Requirement
$ 306,000	5%	$ 291,000

Storm Fund - 2014 **$ 20,000**

Q/E 3/14	
Q/E 6/14	
Q/E 9/14	
Q/E 12/14	
Total Transfer	$ -

Annual Funding Level	% Complete	Funding Requirement
$ 20,000	0%	$ 20,000

Testimony Exhibit JRA-6

Summary of Cash Flow - February 2014

Operating Cash balance forward	$ 140,856	
Projected Purchased Power Expenes:		
ENE	($211,723)	
oject 6 (MMWEC & HQ)	($83,227)	
NYPA	($79,095)	
ENE/ISO	($259,327)	
		($633,372)
Customer Payments	$ 696,050	
NSF cks	($598)	
Payroll, benefits	($125,263)	
Transfer from RF	$7,679	VOIP (Part of NISC Project)
Transfer to RF	($10,000)	February partial contribution
Transfer from PPRF	$155,000	high power bills, low cash flow (See Summary, below)
Transfer to PPRF	($18,230)	(DPI Base rate - February)
Misc. vendor payments	($104,085)	
carry-over encumbered for insurance	$7,000	
Insurance payt	($6,090)	(final)
Encumber for PP - from Feb	$200,000	
Encumber for PP - for March	($187,000)	
	$121,947	

Other Financial Information:

Accounts Payable Balance	$ 10,419
Accounts Receivable Balance	$ 668,789

Summary of Savings/Investments: (Not Restricted)

Contingency/Emergency	$ 10,000	
Storm Fund	$ 19,169	
Working Cash Reserve	$ 60,372	
Dedicated DSM Fund		
Total Savings/Investment (NR)	$ 89,541	
Year-End Reconciliation Account	**$ 5,700**	
Restricted Account(Debt/Capital)	**$ 432,498**	
Restricted Account (RSF)	**$ -**	
Restricted Account(Purchase Pwr)	**$ 199,442**	
Net All Saving/Investment		**$ 727,181**

Summary of PPRF Transfer:

Power Bills Due	$633,372	
Encumbered as of 2/17	$ (480,000)	
	$153,372	(rounded to $155,000)

Misc. Accounts:

Customer Deposit Holding Account	$ 256,870
Working Capital - on Deposit w/ ENE	$ 169,288
Working Capital - on Deposit w/MMWI	$ 2,232

Restricted Fund 2014 **$ 306,000**

Jan-14	$ 15,000
Feb-14	$ 10,000
Mar-14	
Apr-14	
May-14	
Jun-14	
Jul-14	
Aug-14	
Sep-14	
Oct-14	
Nov-14	
Dec-14	$ -
Total Transfer	**$ 25,000**

Annual Funding Level	% Complete	Funding Requirement
$ 306,000	8%	$ 281,000

Storm Fund - 2014 **$ 20,000**

Q/E 3/14	
Q/E 6/14	
Q/E 9/14	
Q/E 12/14	
Total Transfer	**$ -**

Annual Funding Level	% Complete	Funding Requirement
$ 20,000	0%	$ 20,000

Testimony Exhibit JRA-6

Summary of Cash Flow - March 2014

Operating Cash balance forward	$ 121,947		
Projected Purchased Power Expenes:			
ENE	($205,266)		
·oject 6 (MMWEC & HQ)	($84,862)		
NYPA	($99,031)		
ENE/ISO	($205,174)		
		($594,333)	
Customer Payments	$ 927,653		
NSF cks	($845)		
Payroll, benefits	($122,924)		
Transfer from RF	$4,154	2 workstations; and continuation of VOIP project	
Transfer to RF	($20,000)		
Transfer to PPRF	($18,230)	(DPI Base rate - March)	
Misc. vendor payments	($98,793)		
Encumber for PP - from March	$187,000		
Encumber for PP - for Spril	($252,000)		
	$133,629		

Other Financial Information:

Accounts Payable Balance	$ 41,111
Accounts Receivable Balance	$ 521,786

Summary of Savings/Investments: (Not Restricted)

Contingency/Emergency	$ 10,000	
Storm Fund	$ 24,169	
Working Cash Reserve	$ 55,372	
Dedicated DSM Fund		
Total Savings/Investment (NR)	$ 89,541	
Year-End Reconciliation Account	**$ 5,700**	
Restricted Account(Debt/Capital)	**$ 448,344**	
Restricted Account (RSF)	**$ -**	
Restricted Account(Purchase Pwr)	**$ 217,672**	
Net All Saving/Investment		**$ 761,257**

Misc. Accounts:

Customer Deposit Holding Account	$ 256,870
Working Capital - on Deposit w/ ENE	$ 169,288
Working Capital - on Deposit w/MMWE	$ 2,232

Restricted Fund 2014 **$ 306,000**

Jan-14	$ 15,000
Feb-14	$ 10,000
Mar-14	$ 20,000
Apr-14	
May-14	
Jun-14	
Jul-14	
Aug-14	
Sep-14	
Oct-14	
Nov-14	
Dec-14	$ -
Total Transfer	**$ 45,000**

Annual Funding Level	% Complete	Funding Requirement
$ 306,000	15%	$ 261,000

Storm Fund - 2014 **$ 20,000**

Q/E 3/14	$ 5,000
Q/E 6/14	
Q/E 9/14	
Q/E 12/14	
Total Transfer	**$ 5,000**

Annual Funding Level	% Complete	Funding Requirement
$ 20,000	25%	$ 15,000

Summary of Cash Flow - April 2014

Testimony Exhibit JRA-6

Operating Cash balance forward	$ 133,629	
Projected Purchased Power Expenes:		
ENE	($186,862)	
·oject 6 (MMWEC & HQ)	($47,023)	
NYPA	($108,843)	
ENE/ISO	($146,986)	
		($489,714)
Customer Payments	$ 714,394	
NSF cks	$0	
Payroll, benefits	($145,858)	
Transfer to RF	($20,000)	
Transfer to PPRF	($18,230)	(DPI Base rate - April)
Misc. vendor payments	($137,897)	
Encumber for PP - from April	$252,000	
Encumber for PP - for May	($200,000)	
	$88,324	

Other Financial Information:

Accounts Payable Balance	$ 24,231
Accounts Receivable Balance	$ 507,402

Summary of Savings/Investments: (Not Restricted)

Contingency/Emergency	$ 10,000	
Storm Fund	$ 24,169	
Working Cash Reserve	$ 55,372	
Dedicated DSM Fund		
Total Savings/Investment (NR)	$ 89,541	
Year-End Reconciliation Account	**$ 5,700**	
Restricted Account(Debt/Capital)	**$ 468,344**	
Restricted Account (RSF)	**$ -**	
Restricted Account(Purchase Pwr)	**$ 235,902**	
Net All Saving/Investment		**$ 799,487**

Misc. Accounts:

Customer Deposit Holding Account	$ 256,870
Working Capital - on Deposit w/ ENE	$ 169,288
Working Capital - on Deposit w/MMWE	$ 2,232

Restricted Fund 2014 **$ 306,000**

Jan-14	$ 15,000			
Feb-14	$ 10,000			
Mar-14	$ 20,000			
Apr-14	$ 20,000			
May-14				
Jun-14				
Jul-14				
Aug-14				
Sep-14				
Oct-14				
Nov-14		**Annual**	**%**	**Funding**
Dec-14	$ -	**Funding Level**	**Complete**	**Requirement**
Total Transfer	**$ 65,000**	$ 306,000	21%	$ 241,000

Storm Fund - 2014 **$ 20,000**

Q/E 3/14	$ 5,000			
Q/E 6/14				
Q/E 9/14		**Annual**	**%**	**Funding**
Q/E 12/14		**Funding Level**	**Complete**	**Requirement**
Total Transfer	**$ 5,000**	$ 20,000	25%	$ 15,000

Testimony Exhibit JRA-6

Summary of Cash Flow - May 2014

Operating Cash balance forward	$ 88,324	
Projected Purchased Power Expenes:		
ENE	($98,920)	
'oject 6 (MMWEC & HQ)	($83,493)	
NYPA	($65,905)	
ENE/ISO	($125,521)	
		($373,839)
Customer Payments	$ 716,593	
NSF cks	($701)	
Payroll, benefits	($122,357)	
Transfer to RF	($30,000)	
Transfer from RF	$11,386	(NISC Project; Wesco - new data box substation
Transfer to PPRF	($18,230)	(DPI Base rate - May)
Misc. vendor payments	($101,453)	
Encumber for PP - from May	$200,000	
Encumber for PP - for June	($227,000)	
	$142,723	

Other Financial Information:

Accounts Payable Balance	$ 52,565
Accounts Receivable Balance	$ 459,697

Summary of Savings/Investments: (Not Restricted)

Contingency/Emergency	$ 10,000	
Storm Fund	$ 24,169	
Working Cash Reserve	$ 55,372	
Dedicated DSM Fund		
Total Savings/Investment (NR)	$ 89,541	
Year-End Reconciliation Account	**$ 5,700**	
Restricted Account(Debt/Capital)	**$ 486,958**	
Restricted Account (RSF)	**$ -**	
Restricted Account(Purchase Pwr)	**$ 254,132**	
Net All Saving/Investment		**$ 836,331**

Misc. Accounts:

Customer Deposit Holding Account	$ 256,870
Working Capital - on Deposit w/ ENE	$ 169,288
Working Capital - on Deposit w/MMWE	$ 2,232

Restricted Fund 2014 **$ 306,000**

		Annual Funding Level	% Complete	Funding Requirement
Jan-14	$ 15,000			
Feb-14	$ 10,000			
Mar-14	$ 20,000			
Apr-14	$ 20,000			
May-14	$ 30,000			
Jun-14				
Jul-14				
Aug-14				
Sep-14				
Oct-14				
Nov-14				
Dec-14	$ -			
Total Transfer	**$ 95,000**	$ 306,000	31%	$ 211,000

Storm Fund - 2014 **$ 20,000**

		Annual Funding Level	% Complete	Funding Requirement
Q/E 3/14	$ 5,000			
Q/E 6/14				
Q/E 9/14				
Q/E 12/14				
Total Transfer	**$ 5,000**	$ 20,000	25%	$ 15,000

Testimony Exhibit JRA-6

Summary of Cash Flow - June 2014

Operating Cash balance forward	$ 142,723		
Projected Purchased Power Expenes:			
ENE	($118,499)		
roject 6 (MMWEC & HQ)	($84,649)		
NYPA	($33,744)		
ENE/ISO	($81,716)		
		($318,608)	
Customer Payments	$ 655,921		
NSF cks	($600)		
Payroll, benefits	($116,706)		
Transfer to RF	($40,000)		
Transfer from RF	$15,000		AMR Meters (Purchased from Marblehead)
Marblehead Electric	($15,000)		(meters)
Transfer to PPRF	($18,230)		(DPI Base rate - June)
Misc. vendor payments	($137,891)		
Encumber for PP - from June	$227,000		
Encumber for PP - for July	($245,000)		
	$148,609		

Other Financial Information:

Accounts Payable Balance	$ 24,198
Accounts Receivable Balance	$ 461,030

Summary of Savings/Investments: (Not Restricted)

Contingency/Emergency	$ 10,000	
Storm Fund	$ 29,169	
Working Cash Reserve	$ 50,372	
Dedicated DSM Fund		
Total Savings/Investment (NR)	$ 89,541	
Year-End Reconciliation Account	**$ 5,700**	
Restricted Account(Debt/Capital)	**$ 511,958**	
Restricted Account (RSF)	**$ -**	
Restricted Account(Purchase Pwr)	**$ 272,362**	
Net All Saving/Investment		**$ 879,561**

Misc. Accounts:

Customer Deposit Holding Account	$ 256,870
Working Capital - on Deposit w/ ENE	$ 169,288
Working Capital - on Deposit w/MMWE	$ 2,232

Restricted Fund 2014 **$ 306,000**

Jan-14	$ 15,000	
Feb-14	$ 10,000	
Mar-14	$ 20,000	
Apr-14	$ 20,000	
May-14	$ 30,000	
Jun-14	$ 40,000	
Jul-14		
Aug-14		
Sep-14		
Oct-14		
Nov-14		
Dec-14	$ -	
Total Transfer	**$ 135,000**	

Annual Funding Level	% Complete	Funding Requirement
$ 306,000	44%	$ 171,000

Storm Fund - 2014 **$ 20,000**

Q/E 3/14	$ 5,000
Q/E 6/14	$ 5,000
Q/E 9/14	
Q/E 12/14	
Total Transfer	**$ 10,000**

Annual Funding Level	% Complete	Funding Requirement
$ 20,000	50%	$ 10,000

Summary of Cash Flow - July 2014

Testimony Exhibit JRA-6

Operating Cash balance forward	$ 148,609		
Projected Purchased Power Expenes:			
ENE	($172,784)		
·oject 6 (MMWEC & HQ)	($79,534)		
NYPA	($29,980)		
ENE/ISO	($76,661)		
		($358,959)	
Customer Payments	$ 686,369		
NSF cks	($738)		
MMWEC Surplus Funds	$63,968		
Payroll, benefits	($148,516)		
Transfer to PPRF	($18,230)		DPI Base rate - July
Transfer to PPRF	($63,968)		MMWEC Surplus Fund
Transfer from RF	$14,609		$6803 NISC project & $7806 AMR Meter Project
Transfer to RF	($45,000)		
Misc. vendor payments	($101,957)		
Encumber for PP - from July	$245,000		
Encumber for PP - for August	($260,000)		
	$161,187		

Other Financial Information:

Accounts Payable Balance	$ 47,468
Accounts Receivable Balance	$ 528,429

Summary of Savings/Investments: (Not Restricted)

Contingency/Emergency	$ 10,000		
Storm Fund	$ 29,169		
Working Cash Reserve	$ 50,372		
Dedicated DSM Fund			
Total Savings/Investment (NR)	$ 89,541		
Year-End Reconciliation Account	**$ 5,700**		
Restricted Account(Debt/Capital)	**$ 542,349**		
Restricted Account (RSF)	**$ -**		
Restricted Account(Purchase Pwr)	**$ 354,560**		(includes $63,968 from MMWEC Surplus Fund)
Net All Saving/Investment		**$ 992,150**	

Misc. Accounts:

Customer Deposit Holding Account	$ 267,000
Working Capital - on Deposit w/ ENE	$ 169,288
Working Capital - on Deposit w/MMWE	$ 2,232

Restricted Fund 2014 **$ 306,000**

Jan-14	$ 15,000				
Feb-14	$ 10,000				
Mar-14	$ 20,000				
Apr-14	$ 20,000				
May-14	$ 30,000				
Jun-14	$ 40,000				
Jul-14	$ 45,000				
Aug-14					
Sep-14					
Oct-14					
Nov-14					
Dec-14	$ -		**Annual Funding Level**	**% Complete**	**Funding Requirement**
Total Transfer	**$ 180,000**		$ 306,000	59%	$ 126,000

Storm Fund - 2014 **$ 20,000**

Q/E 3/14	$ 5,000			
Q/E 6/14	$ 5,000			
Q/E 9/14				
Q/E 12/14		**Annual Funding Level**	**% Complete**	**Funding Requirement**
Total Transfer	**$ 10,000**	$ 20,000	50%	$ 10,000

Summary of Cash Flow - August 2014

Testimony Exhibit JRA-6

Operating Cash balance forward	$ 161,187	
Projected Purchased Power Expenes:		
ENE	($188,223)	
·oject 6 (MMWEC & HQ)	($84,055)	
NYPA	($31,315)	
ENE/ISO	($94,866)	
		($398,459)

Customer Payments	$ 763,810	
NSF cks	($226)	
Payroll, benefits	($126,827)	
Transfer to PPRF	($17,443)	DPI Base rate - August
Transfer to PPRF	($30,000)	Reimbursement to PPRF
Transfer from RF	$4,536	NISC Project
Transfer to RF	($40,000)	
Misc. vendor payments	($130,593)	
Encumber for PP - from August	$260,000	
Encumber for PP - for September	($300,000)	
	$145,985	

Other Financial Information:

Accounts Payable Balance	$ 42,993
Accounts Receivable Balance	$ 637,218

Summary of Savings/Investments: (Not Restricted)

Contingency/Emergency	$ 10,000
Storm Fund	$ 29,169
Working Cash Reserve	$ 50,372
Dedicated DSM Fund	
Total Savings/Investment (NR)	$ 89,541

Year-End Reconciliation Account	**$ 5,700**	
Restricted Account(Debt/Capital)	**$ 577,813**	
Restricted Account (RSF)	**$ -**	
Restricted Account(Purchase Pwr)	**$ 402,003**	
Net All Saving/Investment		**$ 1,075,057**

Misc. Accounts:

Customer Deposit Holding Account	$ 267,000
Working Capital - on Deposit w/ ENE	$ 169,288
Working Capital - on Deposit w/MMWE	$ 2,232

Restricted Fund 2014 **$ 306,000**

Jan-14	$ 15,000
Feb-14	$ 10,000
Mar-14	$ 20,000
Apr-14	$ 20,000
May-14	$ 30,000
Jun-14	$ 40,000
Jul-14	$ 45,000
Aug-14	$ 40,000
Sep-14	
Oct-14	
Nov-14	
Dec-14	$ -
Total Transfer	**$ 220,000**

Annual Funding Level	% Complete	Funding Requirement
$ 306,000	72%	$ 86,000

Storm Fund - 2014 **$ 20,000**

Q/E 3/14	$ 5,000
Q/E 6/14	$ 5,000
Q/E 9/14	
Q/E 12/14	
Total Transfer	**$ 10,000**

Annual Funding Level	% Complete	Funding Requirement
$ 20,000	50%	$ 10,000

Purchase Power Restricted Fund Reimbursement Summary:

Withdrawals	Jan-14	$ (180,000)	
	Feb-14	$ (155,000)	
	Jul-14	$ 63,968	(MMWEC Project 6 Surplus Funds)
	Aug-14	$ 30,000	
		$ (241,032)	

Testimony Exhibit JRA-6

Summary of Cash Flow - September 2014

Operating Cash balance forward	$ 145,985	
Projected Purchased Power Expenes:		
ENE	($188,237)	
roject 6 (MMWEC & HQ)	($82,357)	
NYPA	($31,583)	
ENE/ISO	($123,625)	
		($425,802)

Customer Payments	$ 890,943	
NSF cks	($168)	
Payroll, benefits	($125,171)	
Transfer to PPRF	($17,698)	DPI Base rate - September
Transfer to PPRF	($30,000)	Reimbursement to PPRF
Transfer to RF	($27,500)	
Misc. vendor payments	($163,637)	
Encumber for PP - from September	$300,000	
Encumber for PP - for October	($350,000)	
	$196,952	

Other Financial Information:

Accounts Payable Balance	$ 15,616
Accounts Receivable Balance	$ 610,884

Summary of Savings/Investments: (Not Restricted)

Contingency/Emergency	$ 10,000	
Storm Fund	$ 34,171	
Working Cash Reserve	$ 45,372	
Dedicated DSM Fund		
Total Savings/Investment (NR)	$ 89,543	
Year-End Reconciliation Account	**$ 5,700**	
Restricted Account(Debt/Capital)	**$ 605,312**	
Restricted Account (RSF)	**$ -**	
Restricted Account(Purchase Pwr)	**$ 449,701**	
Net All Saving/Investment		**$ 1,150,256**

Misc. Accounts:

Customer Deposit Holding Account	$ 267,000
Working Capital - on Deposit w/ ENE	$ 169,288
Working Capital - on Deposit w/MMWE	$ 2,232

Restricted Fund 2014 **$ 306,000**

Jan-14	$ 15,000			
Feb-14	$ 10,000			
Mar-14	$ 20,000			
Apr-14	$ 20,000			
May-14	$ 30,000			
Jun-14	$ 40,000			
Jul-14	$ 45,000			
Aug-14	$ 40,000			
Sep-14	$ 27,500			
Oct-14				
Nov-14		**Annual Funding Level**	**% Complete**	**Funding Requirement**
Dec-14	$ -			
Total Transfer	**$ 247,500**	$ 306,000	81%	$ 58,500

Storm Fund - 2014 **$ 20,000**

Q/E 3/14	$ 5,000			
Q/E 6/14	$ 5,000			
Q/E 9/14	$ 5,000	**Annual Funding Level**	**% Complete**	**Funding Requirement**
Q/E 12/14				
Total Transfer	**$ 15,000**	$ 20,000	75%	$ 5,000

Purchase Power Restricted Fund Reimbursement Summary:

Withdrawal	Jan-14	$ (180,000)	
Withdrawal	Feb-14	$ (155,000)	
Reimbursement	Jul-14	$ 63,968	(MMWEC Project 6 Surplus Funds)
Reimbursement	Aug-14	$ 30,000	
Reimbursement	Sep-14	$ 30,000	
		$ (211,032)	

Testimony Exhibit JRA – 7

Comparison of Requested Rates to Current Rates

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

Column 1			Column 2			Column 3			
Rate Approved December 2013			Rate Approved June 2014			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	$ 0.00568	$ 2.84	Transition	$ 0.00611	$ 3.06	Transition	$ 0.01146	$ 5.73	Schedule H, Line 14
Standard Offer	$ 0.07039	$ 35.20	Standard Offer	$ 0.07736	$ 38.68	Standard Offer	$ 0.06835	$ 34.17	Schedule H, Line 36
Transmission	$ 0.02488	$ 12.44	Transmission	$ 0.02913	$ 14.57	Transmission	$ 0.03283	$ 16.42	Schedule H, Line 25
DSM	$ 0.00230	$ 1.15	DSM	$ 0.00230	$ 1.15	DSM	$ 0.00230	$ 1.15	
Total		$ 77.23	Total		$ 83.06	Total		$ 83.08	
								Mid-Year	
Net Increase/(Decrease)		$ 13.90	Net Increase/(Decrease)		$ 5.84	Net Increase/(Decrease)		$ 0.02	
Percent Increase/(Decrease)		22%	Percent Increase/(Decrease)		8%	Percent Increase/(Decrease)		0.0%	

Transition	$ 0.00568	Transition	$ 0.00611	Transition	$ 0.01146
SOS	$ 0.07039	SOS	$ 0.07736	SOS	$ 0.06835
Transmission	$ 0.02488	Transmission	$ 0.02913	Transmission	$ 0.03283
Total	$ 0.10095	Total	$ 0.11260	Total	$ 0.11264

Testimony Exhibit JRA-7