PASCOAG UTILITY DISTRICT

Pascoag 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

IN RE: PASCOAG UTILITY DISTRICT'S

YEAR END STATUS REPORT

RIPUC DOCKET NO. 4298

**TABLE OF CONTENTS**

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November 4, 2011

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

Re: Year-End Status Report
RIPUC Docket No: 4298

Dear Ms. Massaro:

On behalf of Pascoag Utility District (Pascoag or PUD), we herewith submit an original and nine copies of Pascoag's Year-End Status Report as ordered in the above docket. This submittal consists of three books:

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

In this submittal, Pascoag is proposing two scenarios for Commission consideration. Under ***Option 1***, a residential customer using 500 kilowatt-hours of electricity would see his monthly bill decrease from $74.90 to $66.27, a decrease of $8.63, or 11.5%.

***Option 1*** would flow back the estimated over collection at year end as well as the $200,000 encumbered at year-end December 2010. This money was put in Pascoag's Purchase Power Restricted Fund ("PPRF"), under a Report and Order in RIPUC Docket No. 4211.

| ***Pascoag Option 1*** | **Flow Back of Over Collection and $200,000**** | | |
|---|---|---|---|
| | **Current** | **Proposed** | **Difference** |
| SOS | $0.07064 | $0.05231 | ($0.01833) |
| Transition | $0.01132 | $0.01109 | ($0.00023) |
| Transmission | $0.02290 | $0.02420 | $0.00130 |
| Total | $0.10486 | $0.08760 | ($0.01726) |
| | **** $200,000 encumbered at 12/31/2010** | | |

Under ***Option 2,*** Pascoag would flow back the over collection, but retain the $200,000 encumbered at year-end December 2010 in Pascoag's PPRF. Under this option, a residential customer using 500 kilowatt-hours of electricity would see his monthly bill decrease from $74.90 to $68.18, a decrease of $6.72, or 9%.

***Option 2*** would allow Pascoag to retain the $200,000 encumbered in the PPRF until 2013. Since Pascoag plans to file a Cost of Service Study with the RIPUC in 2012, deferring the flow back of the $200,000 until 2013 would help offset any increase in the base rate by reducing the energy portion of the bill.

| ***Pascoag Option 2*** | **Flow Back Over Collection** | **PUD Retains $200,000 in PPRF**** | |
|---|---|---|---|
| | Current | Proposed | Difference |
| SOS | $0.07064 | $0.05614 | ($0.01450) |
| Transition | $0.01132 | $0.01109 | ($0.00023) |
| Transmission | $0.02290 | $0.02420 | $0.00130 |
| Total | $0.10486 | $0.09143 | ($0.01343) |
| | | ****The $200,000 in the PPRF is retained by Pascoag until 2013** | |

The requested effective date for the new rates is January 1, 2012. 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**
**Year End Status Report RIPUC Docket No. 4298**
**Service List – 2011**

| Name | E-mail | Phone/Fax |
|---|---|---|
| Michael R. Kirkwood<br>General Manager<br>Pascoag Utility District<br>P O Box 107<br>Pascoag, RI 02859 | mkirkwood@pud-ri.org | (401) 568-6222<br>(401) 568-0066 |
| Judith R. Allaire<br>Assistant General Manager<br>Pascoag Utility District<br>P O Box 107<br>Pascoag, RI 02859 | jallaire@pud-ri.org | (401) 568-6222<br>(401) 568-0066 |
| William L. Bernstein, Esq.<br>627 Putnam Pike<br>Greenville, RI 02828 | wlblaw@verizon.net | (401) 949-2228<br>(401) 949-1680 |
| Jon Hagopian<br>Dept. of Attorney General<br>150 South Main Street<br>Providence, RI 02903 | JHagopian@riag.ri.gov<br>David.stearns@ripuc.state.ri.us<br>steve.scialabba@ripuc.state.ri.us<br>tom.ahern@ripuc.state.ri.us<br>John.spirito@ripuc.state.ri.us<br>ltoon@riag.ri.gov<br>Lwold@riag.ri.gov | |
| **Original & nine (9) copies file with:**<br>Luly E. Massaro<br>Commission Clerk<br>Public Utilities Commission<br>89 Jefferson Blvd.<br>Warwick, RI 02889 | Lmassaro@puc.state.ri.us<br>plucarelli@puc.state.ri.us<br>SCCamara@puc-state-ri.us | (401) 941-4500 |

**CERTIFICATE OF SERVICE**

I hereby certify that copy/copies of this filing in Pascoag Utility District's Year End Status Report were served electronically on the individuals named in the above List of Recipients of Filing, this 4 day of November 2011.

Judith R. Allaire

Judith R. Allaire, Notary Public

My commission expires March 28, 2013

**State of Rhode Island and Providence Plantations**
**PUBLIC UTILITIES COMMISSION**

**RE: PASCOAG UTILITY DISTRICT**
RIPUC DOCKET NO. 4298

## 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 January 1, 2012.

| | | | | |
|---|---|---|---|---|
| Standard Offer | Current | $0.07064 | Proposed | $0.05614 |
| Transition Charge | Current | $0.01132 | Proposed | $0.01109 |
| Transmission Charge | Current | $0.02290 | Proposed | $0.02420 |
| | | $0.10486 | | $0.09143 |

A residential customer using 500 kilowatt-hours is currently paying $74.90. Under the proposed rates, this customer's bill would decrease to $68.18, a decrease of $6.72, or 9%.

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 the 4th day of November 2011.

Judith P Allaire

Notary Public

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# Pascoag Utility District – Electric Department

## Year-End Status Report

**RIPUC Docket No. 4298**

Book 1 – Testimony and Testimony Exhibits
Michael R. Kirkwood, General Manager
Judith R. Allaire, Assistant General Manager

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# Index

## Testimony and Exhibits of Michael R. Kirkwood

**Testimony of**

**Michael Kirkwood, General Manager**

**Q. Can you detail Pascoag's power portfolio for 2012?**

**A. M. Kirkwood** Pascoag's power portfolio for 2012 is detailed in *Table 3*, below:

Table 3

**Pascoag Utility District 2012 Power Entitlements**

| | | |
|---|---|---|
| NYPA | 29% | (Hydro) |
| Miller Hydro | 3% | (Hydro) |
| Spruce Mountain | 3% | (Wind) |
| Seabrook | 18% | (Nuclear) |
| Constellation | 47% | (mostly Fossil Fuel) |
| | 100% | |

The total renewable/sustainable power in this portfolio is 35%. This represents mostly hydro power, but a new on-shore wind entitlement, Spruce Mountain, is expected to contribute 3% of the District's total annual purchased energy in 2012.

Pascoag's non-carbon based energy is 53% of its total energy requirements and includes a mix of hydro, on shore wind, and nuclear power. The remaining 47% is mainly fossil fuel based energy through a 3-year contract Pascoag entered into with Constellation Energy. *Testimony Exhibit 1-MRK* highlights this in graph form.

**Q. Please update the Commission on the District's on shore wind entitlement, Spruce Mountain.**

**A. M. Kirkwood** Patriot Renewables, LLC, headquartered in Quincy, Massachusetts has developed a new wind powered facility in Woodstock, Maine that is about to enter commercial production. Spruce Mountain Wind, LLC consists of ten wind turbines, each having a nameplate rating of approximately 2 MW's.

Energy New England ("ENE") contacted several public power systems in New England in 2010 about this particular project, and thirteen including Pascoag responded positively to the opportunity to participate. The capacity of the plant, approximately 20 MW's, is expected to have a thirty-seven percent capacity factor. The plant is to begin commissioning in early November of this year, with commercial operation expected to commence around Thanksgiving. Pascoag's share of the plant output is expected to be over 1,700 MWh each year. Pascoag's share of the facility output is 2.6% of the total plant output.

Although the cost will be $99.25 per MWH, there are some offsets that will reduce the bottom line cost to Pascoag. Based on recently traded Class 1 REC values in the $15 - $30 range, and including the forward capacity market value, the final cost will likely be in the range of $75 per MWH. While the REC values are currently volatile due to uncertainty regarding biomass inclusion in Massachusetts and uncertainty regarding the offshore Cape Wind project, over the long range, REC values could increase to over $30, resulting in an even more attractive bottom line. The term of this contract is fifteen years. *Testimony Exhibit 2-MRK* is a copy of this contract.

**Q. Please provide an update on any new power purchase agreements entered into in 2011.**

**A. M. Kirkwood** Pascoag entered into a contract with Constellation Energy for the years 2012 through 2014 that will replace two short term contracts Pascoag had in place for 2011. The contract, which provides a type of supply arrangement called Load Following Energy, was signed after a competitive bidding process run by ENE on behalf of Pascoag, and was the result of ENE and Pascoag strategizing that market energy prices for the next few years were at a very attractive level due to the recent drop in natural gas prices in the continental United States. Natural gas prices have been and are expected to continue to stay low compared to fuel oil and other sources of energy due to the ability that natural gas producers now have to extract shale gas within the United States. Shale gas reserves are now considered to be in abundance in the United States due to new technologies employed in the industry such as horizontal drilling and fracking that allow economic extraction of this energy supply. See the October 2011 Short-Term Energy Outlook forecast from the U.S. Energy Information Administration for natural gas prices for 2012 (attached as ***Testimony Exhibit 3-MRK***). This forecast is an indication of how shale gas has provided for a very steady expected price stream. Since ISO-NE market clearing prices are predominantly set by natural gas-fired generators which operate on the clearing price margin, Pascoag and ENE theorized that 2011 was a beneficial time to test the market for a longer term deal in order to lock-in the expectation for low natural gas prices for the next few years, and by correlation, low ISO-NE market clearing prices which track natural gas. The RFP turned out to be very successful, allowing Pascoag to lower its Proposed Standard Offer rate for 2012 as presented in the testimony and exhibits of Ms. Allaire.

The Constellation contract will provide very efficient Load Following Energy, such that for each and every hour, Pascoag's load requirement will be compared to the hourly output of Pascoag's other firm entitlements (such as Seabrook, NYPA, Spruce Mountain and Miller Hydro). The need (or gap) in each hour over and above the total of firm entitlements in that hour will be provided by the Constellation contract. In 2012, Constellation will provide 100% of this difference each hour, such that our total expected kWh's purchased from the contract represent 47% of our expected annual load requirement in kWh. Each kWh Pascoag purchases from Constellation over the three year term of the contract will be priced at the very attractive rate of 5.99 cents/kWh. An additional important feature of this arrangement is that since the amount we take is variable each hour in order to match our customer load with our power supply more precisely, we will seldom be in the position of selling excess energy to the ISO-NE market at a price lower than our cost, as sometimes may happen if purchasing firm "around the clock" energy. A copy of the Energy Transaction Confirmation is attached as ***Testimony Exhibit 4-MRK.***

**Q. Has Pascoag been involved with any other projects in procurement of power supply?**

**A. M. Kirkwood** Yes. In early 2011, Pascoag and other public power systems in New England continued to be active participants in conjunction with ENE in discussions for the possibility of purchasing an entitlement share of a combined-cycle plant in Northern Massachusetts. ENE was actively involved in creating this consortium of public power systems that would take the entire plant output.

Pascoag's share was expected to be approximately 3.08%, or 2.3 MW's with the total net plant output estimated at 75 MW's. The plant was to be acquired by a newly formed Special Purpose Entity ("SPE") which would have included fifteen project participants, each with varying shares of the plant. However, in early spring 2011, it was becoming obvious to ENE and the interested public power systems that the transaction would not be concluded, and the parties agreed to halt negotiations.

Pascoag had previously briefed the Division and Commission about this opportunity, and in fact the Division had recommended, pursuant to one of Pascoag's proposed options, for Pascoag to reserve $200,000 of the 2010 purchased power over-collection by placing it into a Rate Stabilization Fund (as part of the Purchased Power Restricted Fund) to partially offset Pascoag's obligations under the SPE described above or, alternatively, to offset future rate increases. Since the SPE discussions have been terminated, Pascoag has a proposal for offsetting future rate increases as more fully described in the Q&A below.

Additionally, ENE continues to be very effective in representing public power entities in New England with various opportunities to purchase required energy, capacity and ancillary services, enabling Pascoag and other public power entities to meet their commitments to provide reliable power market products to their customers. In that regard, ENE is currently working on behalf of its public power constituents with the owner of a natural gas-fired combined-cycle power station in central Rhode Island which is interested in a long term contractual arrangement to sell some or all of the output of the facility to public power entities. Pascoag views this as an opportune time to look at purchases from efficient natural gas-fired facilities for the reasons expressed above in the discussion about the Constellation 3-year Load Following Energy arrangement, and Pascoag will keep the Division apprised as these negotiations with the Rhode Island facility continue.

**Q. In the Report and Order, Docket No. 4211, the Commission granted approval to Pascoag to retain $200,000 of the 2010 over-collection for specific uses. Has Pascoag complied with that requirement?**

**A. M. Kirkwood** Yes. In December 2010, Pascoag deposited $200,000 of the 2010 over-collection to its Purchase Power Restricted Fund ("PPRF") account for the purpose, as specified in the Report and Order in Docket 4211, to establish a Rate Stabilization Fund to be used either for participation in the Special Purpose Entity described above or to offset future rate increases.

Since the negotiations were concluded without an agreement to move forward with the Massachusetts power project and creation of the SPE, Pascoag is requesting here that the RSF amount of $200,000, plus accumulated interest, continue to be held through 2012 in the PPRF account and returned to customers in 2013. Pascoag requests that it be allowed to use these funds as an offset to the base rate increase expected to be put into effect in early 2013. Pascoag and its consultant will be performing a full cost-of-service ("COS") study in the early part of 2012 as previously discussed with the Division in order to file a base rate change request with the Commission and put into place a new base rate structure in 2013. Pascoag's operating costs have continued to increase over the past seven years since its last base rate increase, but its revenues are based on rates first put into effect in January of 2004. Pascoag expects to be filing a request for an increase in rates to cover its prudently incurred operating costs. A return of the full RSF amount of $200,000 plus interest over the 12 month period of 2013 would help to dampen or eliminate the expected base rate impact to Pascoag's customers, and in effect would allow for the rate stabilization that was originally intended and approved in Docket 4211 for these monies.

**Q. Please update the Commission on Pascoag's Restricted Fund for Capital and Debt Service, and what, if any, fiscal issues Pascoag encountered during 2011.**

**A. M. Kirkwood** In previous years since inception of the Capital Restricted Reserve Fund in 2004, Pascoag successfully funded the annual requirement of $376,000 to this fund. However, in 2011 due to insufficient revenues to cover all operating and capital costs, Pascoag requested the Commission to allow it to fund the 2011 Restricted Capital account to the lower level of $185,000, and the 2012 Restricted Capital account to $62,500.

The establishment of this fund in 2004 has allowed Pascoag to purchase needed capital items, including vehicles, with no new debt service obligations and also to pay off its debt obligations. In fact, the electric department currently has no long-term debt.

However, Pascoag has found itself in the difficult position of inadequate coverage to fund the Restricted Fund for Capital and Debt Service for 2011 and 2012, and therefore requested the Commission in September of 2011 for the lower funding levels mentioned above.

In 2012, Pascoag will defer the purchase of a new bucket truck, capital improvements to the business office, and the purchase of a pickup truck. Because of Pascoag's attention to a solid preventative maintenance schedule, the District's vehicle fleet is in excellent condition. The bucket truck that was to have been replaced in 2012 is a 1994 International, but since these types of vehicles have limited mileage, a twenty-year life is not unusual. These short term deferrals or reductions will in no way impede the District's ability to provide reliable electric service to its customers, while maintaining safe working conditions for its employees. Additionally, Pascoag has successfully built the Restricted Capital fund to the level of approximately $500,000, and as long as Pascoag reduces its capital expenditures in 2011 and 2012 to coincide with the lower funding infusion, Pascoag will be able to maintain the account at approximately $500,000 through this difficult period.

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

**A. M. Kirkwood** The District now has EEI Master Power Purchase and Sales Agreements in place with TransCanada, NextEra Energy, Constellation Energy and Macquarie Energy. These documents improve Pascoag's position in contract negotiations, and once created, can be easily modified to include the District's other energy suppliers. The agreements streamline the negotiation process by ensuring Pascoag's credit worthiness to potential new partners. In fact, it was the use of EEI Master Agreements which allowed the competitive solicitation that resulted in the beneficial 3-year Load Following Energy deal with Constellation Energy discussed above. These EEI Masters allow the parties to transact quickly based on market conditions at the time the transactions are priced.

Additionally, Pascoag management including myself and Judy Allaire recognized early on in 2011 that revenues were inadequate to cover operating and capital costs completely. Although Pascoag has always been very prudent in its expenditures, due to the challenging two years until new rates can be put into place, I instituted a restriction on significant operating and capital expenditures so that we could more easily manage our way through this financially challenging period. We have made such budgetary cuts only with expenditures that do not jeopardize the safety or reliability of our customers and employees.

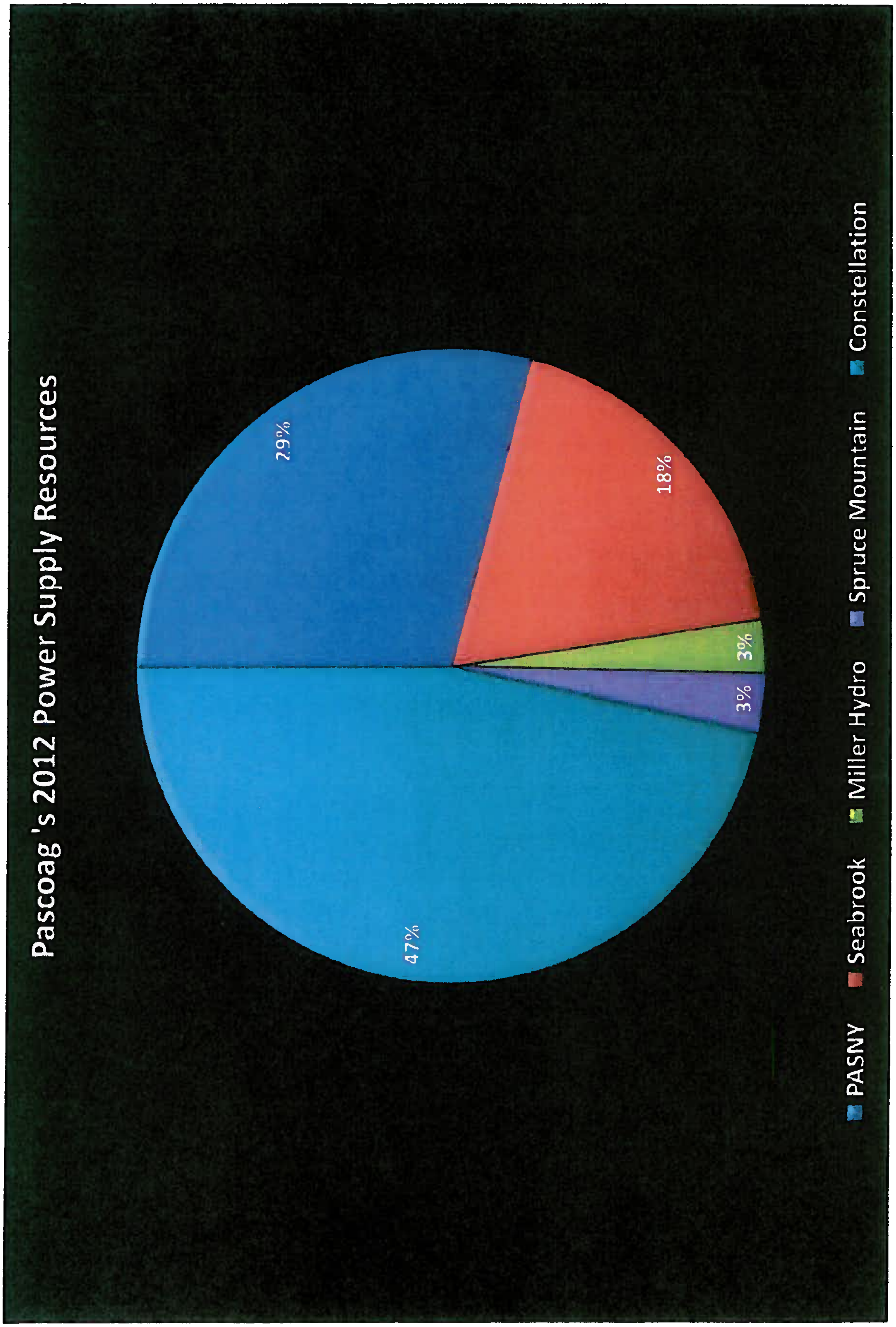
Finally by way of important information regarding Pascoag's fiscal health, on January 6, 2011, Pascoag was notified by Standard and Poor's that they had affirmed the District's "A-"credit rating based on the results of their annual review and rating performed in 2010. Pascoag has now maintained an A- rating with S&P from 2008 to the present.

**Q. Does this conclude your portion of the testimony?**

**A. M. Kirkwood**

Yes it does.

**Exhibit 1-MRK**



# POWER PURCHASE AGREEMENT

# FOR

# UNIT CONTINGENT ENERGY, CAPACITY AND RENEWABLE ENERGY CERTIFICATES

# BETWEEN

# PASCOAG UTILITY DISTRICT

# AND

# SPRUCE MOUNTAIN WIND, LLC

This POWER PURCHASE AGREEMENT ("Agreement") is made and entered into as of October 1, 2010 (the "Effective Date") by and between the Pascoag Utility District, having its principal place of business at Pascoag, Rhode Island, hereinafter referred to as "Buyer", and Spruce Mountain Wind, LLC, having its principal place of business at 549 South Street, Building 19, Quincy, Massachusetts 02169, hereinafter referred to as "Seller" (Buyer and Seller are referred to herein individually as a "Party" and collectively the "Parties").

WHEREAS, Seller owns the Facility (as defined below) and wishes to sell to Buyer a certain percent of the output of the Facility and all Contract Products (as defined below) related to such output; and

WHEREAS, Buyer serves load and wishes to purchase a certain percent of the output of the Facility and all Contract Products related to such output,

Now, therefore, in accordance with the foregoing and in consideration of the mutual promises and agreements set forth herein, Buyer agrees to purchase from Seller and Seller agrees to provide to all of the output of the Facility and all Contract Products related to such output in accordance with the following provisions.

## ARTICLE 1.
## DEFINITIONS

Any term that is capitalized herein but not defined below shall be defined in accordance with the definitions contained in the ISO-New England, Inc. Transmission, Markets and Services Tariff as it may hereafter be amended from time to time, or a successor set of market rules taking effect within the term of this Agreement ("ISO-NE Rules").

1.01 "Buyer's Credit Support Amount" has the meaning set forth in Article 19.2.

1.02 "Business Day" shall mean any day except a Saturday, Sunday, or a Federal Reserve Bank holiday. A Business Day shall open at 8:00 a.m. and close at 4:00

p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance, shall be the Party from whom the notice, payment or delivery is being sent.

1.03 "Closing Date" shall have the meaning set forth in Article 19.1.

1.04 "Commercial Operation Date" shall mean the date the Seller confirms as the date of commencement of commercial operation of the Facility by letter to the Transmission Owner and ISO-NE in conformance with Attachment A to Attachment 8 of the ISO-NE Small Generator Interconnect Procedure - Schedule 23.

1.05 "Commercially Reasonable Efforts" shall mean a level of effort which in the exercise of prudent judgment in the light of facts or circumstances known, or which should reasonably be known, at the time a decision is made, can be expected by a reasonable person to accomplish the desired result in a manner consistent with Good Industry Practice and which takes the performing Party's interests into consideration. "Commercially Reasonable Efforts" will not be deemed to require a Party to undertake unreasonable measures or measures that have an adverse economic affect on such Party, including the payment of sums in excess of amounts that would be expended in accordance with Good Industry Practice.

1.06 "Commissioned" shall mean, with respect to any wind turbine, that such wind turbine has been installed and that Seller has taken all action necessary to enable the wind turbine to commence the regular delivery and sale of Contract Products to Buyer.

1.07 "Commissioning Deadline" means June 30, 2012, which date shall be extended on a day-for-day basis, or such longer period as may be appropriate under the circumstances, for any delay in Commissioning one or more of the wind turbines at the Facility due to Force Majeure or action or inaction on the part of Interconnecting Utility.

1.08 "Contract Energy Price" shall mean $99.25 per MWh on and after the Commercial Operation Date. Prior to the Commercial Operation Date the Contract Energy Price shall mean $89.325 per MWh.

1.09 "Contract Products" shall mean 2.608 percent of the products produced by the Facility or any other attribute associated with the output of the Facility, including, but not limited to Energy, Installed Capacity, Ancillary Services, Renewable Energy Certificates and Environmental Attributes.

1.10 "Costs" shall mean, with respect to the Non-Defaulting Party, brokerage fees, commissions and other similar third party transaction costs and expenses reasonably incurred by such Party in entering into new arrangements which replace the terminated transaction but only as the same relates specifically to this Agreement; and all reasonable attorneys' fees and expenses incurred by the Non-

Defaulting Party in connection with the termination of the transaction but only as the same relates specifically to this Agreement.

1.11 "Credit Rating" means the rating assigned to a Party by Moody's or S&P for a Party's long term unsecured debt not supported by third party credit enhancement (other than by repayment of its debt) or, if such Party does not issue long term debt, then the rating then assigned to such entity as a long-term issuer rating by Moody's or S&P.

1.12 "Defaulting Party" has the meaning set forth in Article 13.1.

1.13 "Delivery Point" has the meaning set forth in Article 5.

1.14 "Due Date" has the meaning set forth in Article 9.2.

1.15 "Early Termination Date" has the meaning set forth in Article 13.2.

1.16 "Energy" shall mean the power that the Facility produces in the form of electricity measured in kilowatt hours or megawatt hours.

1.17 "Effective Date" means the date of execution of this Agreement.

1.18 "Environmental Attributes" means those attributes that are aspects, claims, characteristics or benefits associated with the generation of a quantity of electricity by the Facility, other than the electric energy produced and that are capable of being measured, verified or calculated and are documented or classified in the NEPOOL GIS during the Term of this Agreement. An Environmental Attribute may include, but is not limited to, one or more of the following identified with a particular megawatt hour of generation: the Facility's use of a particular renewable energy source, avoided NOx, SOx, $CO_2$, greenhouse gas emissions or avoided water use (but not water rights or other rights or credits obtained pursuant to requirements of applicable law in order to site and develop the Facility itself). Environmental Attributes may or may not be included in the definition or valuation of Renewable Energy Certificates by various certification authorities for use in meeting requirements of renewable portfolio standards under their jurisdiction. Environmental Attributes do not include (i) any Installed Capacity of the Facility, or (ii) any Tax Benefits.

1.19 "Event of Default" shall have the meaning set forth in Article 13.1.

1.20 "Facility" shall mean a wind-powered electric generating facility consisting of up to ten wind turbines, each having a nameplate rating of 2 MWs, to be constructed by Seller in the Town of Woodstock, Maine.

1.21 "Force Majeure" shall mean any cause beyond the reasonable control of, and not the result of negligence, or the lack of due diligence of, the Party claiming suspension of performance as a result thereof. Neither economic harm to a Party nor the financial condition of a Party shall constitute Force Majeure hereunder.

Force Majeure shall include, without limitation, strike, stoppage in labor, riot, fire, flood, ice, invasion, civil war, commotion, insurrection, blockades, embargoes, sabotage, epidemics, explosions, acts of terrorism, military or usurped power, order of any court granted in any bona fide adverse legal proceeding or action (not brought by either Party), order of any civil, military or governmental authority (either de facto or de jure and including, without limitation, orders of governmental and administrative agencies which conflict with the terms of this Agreement), failure of any governmental authority to act, or material delay in any such action, including material delay attributable to the appeal of any governmental action (provided that such action has been timely requested and diligently pursued), and acts of God or public enemies. Seller shall be deemed to have suffered an event of Force Majeure due to the failure of equipment for which it is responsible for operating or maintaining if the equipment has been operated and maintained in accordance with Good Industry Practice.

1.22 "Generator Asset" has the meaning set forth in the ISO-NE Rules.

1.23 "Forced Outage" means that term as defined in the Scheduling Procedure.

1.24 "Good Industry Practice" shall mean the practices, methods and acts (including but not limited to the practices, methods and acts engaged in or approved by a significant portion of the electric generation industry in the operation and maintenance of generating equipment similar in size and technology to the Facility) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with law, regulation, reliability, safety, environmental protection, economy and expedition.

1.25 "Information" shall mean all records, reports, communications, papers, maps, photographs, financial statements, statistical tabulations, or other documentary materials or data, regardless of physical form or characteristics, made, received or otherwise possessed by Seller pertaining to the Facility, any portion thereof, the Interconnection, or this Agreement.

1.26 "Interest Rate" has the meaning set forth in Article 9.2.

1.27 "Interconnecting Utility" shall mean the electric utility to which Energy and other Contract Products are transferred through the Interconnection.

1.28 "Interconnection" shall mean generator step-up transformers, primary switchgear, system protection and metering equipment owned by Seller or the Interconnecting Utility, and agreements between Seller and the Interconnecting Utility, that effect the physical transfer of Energy and other Contract Products from the Facility to the Interconnecting Utility for delivery to the Delivery Point.

1.29 "Intermittent Power Resource" shall have the meaning given in the ISO-NE Rules.

1.30 "Investment Grade Credit Rating" shall mean a Credit Rating of at least BBB- from S&P and/or a Credit Rating of at least Baa3 from Moody's.

1.31 "Liabilities" means any and all liabilities, losses, fines, obligations, penalties, costs or other expenses of any kind or nature, including reasonable attorneys', experts' and accountants' fees, court costs and other costs of any proceeding, incurred by a Person, whether arising from claims, demands, causes of action, litigation, lawsuits, proceedings, investigations, judgments, settlements or from any similar type of occurrence whether actual, threatened or filed and regardless of whether groundless, false or fraudulent..

1.32 "Leading Market Maker" shall mean a firm that is active in trading wholesale Energy in the ISO-NE market and that is commonly recognized in the industry as a leading trader of wholesale Energy at the time that a request for proposals is issued to it pursuant to Article 13.2.

1.33 "Lead Market Participant" shall have the meaning set forth in the ISO-NE Rules.

1.34 "Letter of Credit" means one or more irrevocable, transferable standby letters of credit issued by a Qualified Institution, and otherwise being in a form reasonably acceptable to the Party in whose favor the Letter of Credit is issued. Costs of a Letter of Credit shall be borne by the applicant for such Letter of Credit. A Letter of Credit shall be valued at zero unless it expires more than thirty (30) days after the date of valuation.

1.35 "Letter of Credit Default" has the meaning set forth in Articles 19.1(b).

1.36 "Losses" shall mean, with respect to any Party, an amount equal to the present value of the economic loss to it, if any (exclusive of Costs), resulting from termination of this Agreement, determined in a commercially reasonable manner, in accord with market value in the ISO-NE Market. Each present value calculation shall be made using as a discount rate the yield on US Treasury Bills or Bonds, as the case may be, in effect on the day the calculation is made, as identified in Bloomberg Online or as published in The Wall Street Journal.

1.37 "Maintenance Outage" means that term as defined in the Scheduling Procedure.

1.38 "Material Contract" shall, as of the Commercial Operation Date, mean any written contract, agreement, license, sublease, lease, easement, sublease, mortgage, instrument, guarantee, commitment, undertaking or other similar arrangement, whether expressed or implied, which either:

(i) creates a right to lease, use or occupy real estate which is necessary for the operation of the Facility according to Good Industry Practice; or

(ii) provides rights or benefits for the Seller such that the consequences of a default under or termination of such an arrangement would reasonably be expected to have a material adverse effect upon Seller's ability to operate the Facility according to Good Industry Practice.

1.39 "Monthly Contract Products Charge" has the meaning set forth in Article 4.2.

1.40 "Moody's" shall mean Moody's Investors Service, Inc.

1.41 "New Generating Capacity Resource" shall mean a type of resource participating in the Forward Capacity Market, as described in the ISO-NE Rules.

1.42 "Non-Defaulting Party" has the meaning set forth in Article 13.1.

1.43 "Other Purchasers" means the Belmont Municipal Light Department, the Braintree Electric Light Department, the Concord Municipal Light Plant, the Hingham Municipal Light Plant, the Georgetown Municipal Light Department, the Groveland Electric Light Department, the Middleton Electric Light Department, the Merrimac Municipal Light Department, the North Attleborough Electric Department, the Norwood Municipal Light Department, the Pascoag Utility District, the Rowley Municipal Light Plant, and the Wellesley Municipal Light Plant.

1.44 "Person" means an individual, partnership, corporation, business trust, joint stock company, trust, unincorporated association, joint venture, governmental entity, limited liability company, or any other entity of whatever nature..

1.45 "Planned Outage" means that term as defined in the Scheduling Procedure.

1.46 "Planned Maintenance" means maintenance of the Facility that is planned in advance and is scheduled in accordance with ISO-NE Operating Procedures as a Planned Outage or a Maintenance Outage.

1.47 "Qualified Capacity" shall mean the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

1.48 "Qualified Institution" shall mean a U.S. commercial bank or a U.S. branch of a foreign bank (which is not an affiliate of either Party) with such bank having a credit rating of at least A- from Standard & Poor's Rating Group ("S&P") and A3 from Moody's Investor Service ("Moody's"), having $10,000,000,000 in assets. The National Rural Utilities Cooperative Finance Corporation shall be considered a Qualified Institution.

1.49 "Received" has the meaning set forth in Article 9.2.

1.50 "Renewable Energy Certificates" means the certificates, which relate to each MWh of generation from the Facility, that are produced, documented or classified in the NEPOOL GIS according to their ability to meet renewable portfolio standards requirements in any New England State or under any applicable federal program.

1.51 "S&P" shall mean Standard and Poor's Rating Group.

1.52 "Scheduling Procedure" means ISO New England Operating Procedure No. 5 - Generator and Dispatchable Asset Related Demand Maintenance and Outage Scheduling Effective Date: October 13, 2006. Revision No. 8, as in effect on the date of this Agreement.

1.53 "Seller's Credit Support Amount" has the meaning set forth in Article 19.1.

1.54 "Settlement Amount" shall have the meaning set forth in Article 13.2.

1.55 "Tax Benefits" means any tax benefits associated with ownership or operation of the Facility including without limitation production tax credits, investment tax credits, depreciation or any similar benefit, and any grant in lieu of any of the foregoing, including, without limitation, any grant received by Seller pursuant to section 1603 of the American Recovery and Reinvestment Act of 2009.

1.56 "Term of Agreement" has the meaning set forth in Article 2.3.

1.57 "Term of Service" has the meaning set forth in Article 2.2.

1.58 "Termination Payment" shall have the meaning set forth in Article 13.2.

1.59 "Transferred Generator Asset" has the meaning set forth in Article 4.1.

1.60 "Unplanned Maintenance" means all maintenance on the Facility during a Forced Outage.

## ARTICLE 2.
## TERM OF SERVICE

2.1. Seller shall Commission at least eight of the wind turbines comprising the Facility on or before the Commissioning Deadline. Seller shall provide Buyer with a copy of each commissioning certificate for each wind turbine that it receives from the wind turbine manufacturer. Seller shall provide a copy of each such commissioning certificate to Buyer within three (3) Business Days of receipt by Seller. If Seller fails to Commission at least eight of the wind turbines comprising the Facility by the Commissioning Deadline, then Buyer shall have the right to extend the Commissioning Deadline or to terminate this Agreement without any liability whatsoever on the part of either Party, and if so terminated this Agreement shall then become null and void and of no effect whatsoever. Buyer shall notify Seller of its exercise of the foregoing right within fifteen (15) days after the Commissioning Deadline, and if Buyer fails to so notify Seller, Buyer shall be deemed to have elected to terminate this Agreement.

2.2. Term. Subject to Article 2.1 above, Seller shall commence selling the Contract Products, and Buyer shall commence purchasing the Contract Products on the date on which the first wind turbine at the Facility is Commissioned and the applicable percent of the Generator

Asset has been transferred to Buyer pursuant to Article 4.1, and Seller shall continue selling the Contract Products, and Buyer shall continue purchasing the Contract Products, from each Commissioned wind turbine at the Facility, as provided herein, through the earlier of (i) HE 2400 on the day fifteen (15) years following the Commercial Operation Date, or (ii) the date of termination pursuant to the provisions of Article 13.2 ("Term of Service").

2.3. The applicable provisions of this Agreement shall commence on the Effective Date and 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 ("Term of Agreement"). Notwithstanding anything in the Agreement to the contrary, expiration or termination of the Agreement for any reason shall not relieve either Party of any right or obligation accrued or accruing hereunder prior to such expiration or termination, and no expiration or termination of this Agreement shall affect or excuse the performance of either Party under any provision of this Agreement that by its terms survives any expiration or termination.

## ARTICLE 3.
## TRANSACTION TYPE AND SELLER OBLIGATIONS

3.1. This Agreement is for the purchase of 2.608 percent of the Contract Products produced by the Facility or attributable to the Facility. The Facility will consist of up to ten wind turbines. Seller will notify Buyer on or before June 30, 2011 how many wind turbines will be included in the Facility.

3.2. The Parties understand and agree that as of the Effective Date Buyer has a retail load-serving obligation and that Buyer is entering into this Agreement, in part, to satisfy all or a portion of such obligation and requirement. Thus, the Parties understand and agree that Seller shall use Commercially Reasonable Efforts consistent with Good Industry Practice to maximize the availability of the Facility in order to maximize the amount of Energy, Renewable Energy Credits, and other Contract Products that Buyer will receive hereunder.

3.3. Planned Maintenance. Seller shall schedule and perform all Planned Maintenance in accordance with the Scheduling Procedure. Prior to performing or causing the performance of any Planned Maintenance, Seller shall notify Buyer upon the earlier of: (a) notification to ISO-NE and (ii) May 1st of each year of Planned Maintenance Seller intends to schedule for the First Future Year, and upon notification to, or from, ISO-NE of any additions or changes to the Planned Maintenance Schedule. All Planned Maintenance will be done in accordance with ISO-NE procedures for intermittent power resources.

3.4. Forced Outage. Seller shall use Commercially Reasonable Efforts consistent with Good Industry Practice to fully resolve any Unplanned Maintenance as quickly as possible. Seller shall notify Buyer of any Unplanned Maintenance activities as soon as reasonably possible after Seller learns of the need for such activities, but in no event later than twenty-four hours after learning of such need. Seller shall comply with the Scheduling Procedure regarding Forced Outages when performing Maintenance.

3.5. Regulatory Status. Seller shall obtain and maintain such authorizations, certificates and approvals as may be required from the Federal Energy Regulatory Commission ("FERC") as may be required for Seller to make wholesale electricity sales to Buyer at the rates and on the terms set forth under this Agreement, which Seller acknowledges is a market based rate.

3.6 Obligation to Provide Information. Seller shall provide to Buyer copies of all Information within a reasonable period of time, but in no event later than fifteen (15) days, of making or receiving Information pertaining to: (i) communications between the Seller and ISO-New England and/or the Interconnecting Utility pertaining to the Facility, any portion thereof, the Interconnection, or this Agreement; and, (ii) maintenance and/or repair pertaining to the Facility or any portion thereof or the Interconnection.

3.7 If Buyer is required to provide any Information to ISO-New England as a result of the transfer of the Generator Asset ownership to Buyer, then upon written request by Buyer, Seller shall provide such Information to Buyer within fifteen (15) days of such request. If Seller does not possess or have reasonable access to such information and/or documentation then Seller shall so notify Buyer as soon as reasonably practicable, but in no event later than fifteen (15) days after such request is made.

3.8. Capacity Qualification. At its sole expense, the Seller shall qualify the Facility for the Forward Capacity Market as a New Generating Capacity Resource that is an Intermittent Power Resource and shall maintain such qualification throughout the Term of Service. If the Buyer elects, in its sole discretion, to designate its Contract Products percentage of the Installed Capacity as self-supply for the Buyer's benefit then Seller shall use commercially reasonable efforts to comply with Buyer's election.

3.9 Adjustment for FCM Settlement. In the event that Seller and not Buyer receives payments from ISO-NE for Forward Capacity, the Monthly Contract Products Charge shall be reduced by an amount equal to percentage of Contract Products purchased by Buyer, as set forth in the definition of Contract Products, multiplied by any such payments received by Seller.

3.10. NERC Compliance. The Parties understand and agree that the Seller, and not the Buyer, shall be responsible for compliance with the North American Electric Reliability Corporation (NERC) Compliance Monitoring and Enforcement Program as such compliance relates to the Seller's obligations under this Agreement and/or ownership and/or operation of the Facility.

3.11. Lead Market Participant. The Parties understand and agree that the Seller, and not the Buyer, shall be responsible for all Lead Market Participant obligations and responsibilities.

## ARTICLE 4.
## PURCHASE AND SALE OF CONTRACT PRODUCTS

4.1. Sale of Contract Products. Seller shall transfer or otherwise cause a transfer of percent (2.608%) ownership share of the Generator Asset representing the Facility to Buyer on or prior to the Commercial Operation Date using the ISO-NE's Asset Registration Process

("Transferred Generator Asset"). Any such transfer shall be solely for purposes of ISO New England's settlement procedures, and shall not in any way affect the legal ownership of the Facility. At the end of the Term of Service, Buyer covenants to transfer and return the Transferred Generator Asset to the Seller. In the event of early termination of this Agreement pursuant to Article 13 as a result of a Buyer committed Event of Default, the Buyer agrees and covenants to cease receiving any and all Contract Products pertaining to the Facility and further covenants to transfer and return the Transferred Generator Asset to the Seller.

4.2. Payment for Contract Products. Buyer will pay Seller each month an amount equal to the number of kilowatt-hours received by Buyer in its ISO settlement multiplied by the Contract Energy Price ("Monthly Contract Products Charge").

4.3. Seller shall use Commercially Reasonable Efforts to obtain a Capacity Supply Obligation from another resource that is qualified to provide capacity in Maine by the first day of the month that is three calendar months following the Commercial Operation Date, in an amount (in MWs) equivalent to the amount of Capacity Supply Obligation that the Unit would have received had it participated in each applicable Forward Capacity Auction ("FCA") through May 31, 2014.

4.4. Penalty for Failure to Qualify Capacity. Beginning with the fifth FCA which shall be held to establish Forward Capacity Market ("FCM") prices for the June 2014 through May 2015 period, in the event that Seller fails to qualify the Facility for the FCM in accordance with Article 3.8 of this Agreement, then until such time as the Facility becomes qualified for the FCM and Buyer receives credit or is credited by Seller, as applicable, for capacity the Monthly Contract Products Charge will be reduced by an amount equal to the product of (a) twenty-five percent (25%) of the nameplate rating of the Facility, in MW and (b) the Capacity Clearing Price from the Forward Capacity Auction in effect for the month.

## ARTICLE 5.
## DELIVERY POINT

The Delivery Point for electric energy will be the Node as determined by ISO-New England pursuant to the Seller's interconnection study, which shall be a PTF point. Seller shall be responsible for all losses up to the Delivery Point.

## ARTICLE 6.
## TRANSMISSION

Seller shall be responsible for all transmission arrangements and all costs associated therewith, necessary to deliver and transmit the Energy sold hereunder up to the Delivery Point. Buyer shall be responsible for all transmission arrangements, and all costs associated therewith, necessary to receive and transmit the Energy purchased hereunder from the Delivery Point to the consumption point meters registering Buyer's load including, without limitation, all costs for any Regional Network Service ("RNS") and Local Network Service ("LNS") associated with the Buyer's load.

## ARTICLE 7.
## METERING

Electricity provided by Seller from the Facility shall be metered by Seller at the Delivery Point. Seller shall calibrate and maintain metering equipment in accordance with ISO New England standards. If at any time metering equipment associated with the Facility is found to be inaccurate by ISO New England's metering standards, Seller shall cause it to be made accurate by repair or replacement. The meter readings for the period of inaccuracy shall be adjusted by Seller to correct such inaccuracy so far as the same can be reasonably ascertained; otherwise, the inaccuracy will be deemed to have existed for one half (1/2) of the time period which elapsed between the date such equipment last tested accurate and the date that such equipment was found inaccurate. In addition to regular routine tests, which shall be made in accordance with ISO New England standards, Seller shall cause such equipment to be tested at any time upon request of and in the presence of a representative of Buyer, but in no event may Buyer request more than one test per year. If such equipment proves accurate within ISO New England's metering standards, when tested upon request of Buyer in addition to regular routine tests, the expense of such test shall be borne by Buyer.

## ARTICLE 8.
## RENEWABLE ENERGY CERTIFICATES

8.1. Seller's Registration Obligations. The Seller shall register the Facility, as necessary, and to the extent the Facility qualifies, so that the Facility is compliant with reporting requirements related to Renewable Energy Certificates, Environmental Attributes, certification in the New England States, including but not limited to the Commonwealth of Massachusetts, or under any applicable federal program and under the Green-E certification program. Such registration shall include, but not be limited to, registering the unit so that it is compliant with NEPOOL GIS reporting requirements relative to renewable portfolio standards. The Seller shall be obligated to maintain such registrations throughout the Term of Service. The Seller shall be responsible for all initial and ongoing costs to establish and maintain such registrations pertaining to the New England States, any applicable federal program and the Green-E certification program including, but not limited to, consultant, legal or other fees or expenses incurred, but shall not be obligated to incur any cost to modify the Facility so that it complies with the requirements of such programs to the extent that such requirements change from those in existence as of the date of this Agreement. Buyer shall assist, cooperate and consult with Seller to the extent reasonably requested by Seller in all such processes at Buyer's sole expense.

8.2. Seller's Obligations with respect to Green-E Certification. Notwithstanding anything to the contrary in this Article 8, Seller's obligations hereunder with respect to registration or qualification of the Facility under the Green-E certification program shall consist solely of providing information required for such registration or qualification and shall in no event impose any certification fee obligations or any further obligations or conditions on Seller in addition to those imposed under applicable state and federal programs.

8.3. To the extent that the acts or omissions of Seller or its agent, as applicable, cause failure to deposit Renewable Energy Certificates (or Environmental Attributes, as applicable) in Buyer's NEPOOL GIS Account in an amount equal to the MWhs of Energy delivered to the

Delivery Point during such month ("Deficient REC Amount") and the Facility qualified for such RECs or other Environmental Attributes, then Seller shall, within 30 days after written notification from Buyer, deposit in Buyer's NEPOOL GIS Account substitute Renewable Energy Credits (or Environmental Attributes, as applicable) equal to the Deficient REC Amount. Buyer shall specify to Seller the REC Type that shall be deposited into Buyer's NEPOOL GIS Account and Seller shall deposit such RECs (and/or Environmental Attributes, as applicable) in the Deficient REC Amount.

## ARTICLE 9.
## BILLING AND PAYMENT

9.1. Calculation of Monthly Invoice. For each month or portion thereof during the Term of Service, and, except as otherwise expressly provided herein, Buyer shall pay to Seller an amount equal the Monthly Contract Products Charge. Pending the availability of actual data, computations by Seller of charges for the purposes of billings hereunder may be based upon estimates made by Seller. Any charges that are based upon estimates shall be trued-up as soon as practicable once actual data becomes available. Errors in arithmetic, computation, meter readings, estimating, or otherwise that affect the accuracy of a bill shall be promptly corrected in a subsequent corrected bill.

9.2. Presentation and Payment. Unless otherwise agreed to in writing by the Parties: (i) Seller shall submit an invoice to Buyer for the Monthly Contract Product Charge and the respective amounts due under the terms of this Agreement as soon as practicable after the end of each calendar month during the Term of Service; (ii) the invoice shall identify each input on the bill which is based upon an estimate, in whole or in part; (iii) invoices shall be delivered to Buyer by facsimile or by mutually agreed upon electronic means, followed up by an original invoice delivered by regular mail; (iv) all such invoices shall be due and payable in immediately available funds via wire transfer no later than the Due Date, defined as fifteen (15) Business Days after the date on which such invoice is Received; and (v) any amounts not paid by the Due Date shall be deemed delinquent and shall accrue interest from the Due Date to the date of payment at a per annum rate of interest equal to the prime lending rate as may from time to time be published in The Wall Street Journal under "Money Rates" as the same may change from to time (or if not published on such day on the most recent preceding day on which published), or any other periodical that may be agreed upon in writing from time to time, plus two percent (2%) ("Interest Rate"). For purposes of this Article 9.2, "Received" shall mean the date that the invoice is confirmed successfully delivered by telecopy, express mail or electronic communication. In the event that any Due Date falls on a weekend or a NERC holiday, such payment shall be due on the first business day thereafter. If Buyer fails to pay any amounts when due hereunder, Seller shall have the right to exercise any remedy available under this Agreement or at law or in equity to enforce payment of such amount plus interest at the Interest Rate and costs of collection, including reasonable attorney fees.

9.3. Challenge of Invoices. Unless otherwise agreed, in the event of a good faith dispute relating to the amounts set forth on any invoice, and provided that the undisputed portion of the invoice at issue is paid, then: (i) either Party may challenge, in writing, the accuracy of any original or adjusted invoice, provided that no adjustment for any invoice or payment will be made unless the challenge to the accuracy thereof was made prior to the lapse of twenty four (24) months from the receipt thereof; (ii) if a Party does not challenge the accuracy of an original or adjusted invoice within such twenty four (24) month period, such invoice shall be binding upon that Party and shall not be subject to challenge.

9.4. Disputed Invoice. Within the limitation of Article 9.3, each invoice shall be subject to adjustment for true-up from estimated costs to actual costs, errors in arithmetic, computation or estimating, or adjustments related to ISO-NE settlement, or as otherwise applicable. Seller may make adjustments to any billing for a period of up to twenty four (24) months from the date of rendering of such original billing in order to reflect differences in Seller's receipt of more current data. The Parties shall use good faith efforts to resolve any billing and payment disputes promptly. Unless otherwise agreed, in case of a dispute to any portion of any invoice, only the non-disputed amount shall be paid in accordance with Article 9.2. Unless otherwise agreed, upon final determination of the invoice amount, any necessary adjustments in such invoice and the payments thereof shall be made in the invoice submitted in the month following such determination, with interest at the Interest Rate from the original Due Date of the invoice until the date of payment. Buyer's payment of an invoice (whether or not under protest) shall not affect any legal or equitable rights a Party may have to challenge the invoice within the time limitations established in Article 9.3 above.

9.5. Monthly Payment Netting. Except for amounts that one Party may owe to the other under Articles 13 and 19, which amounts shall not be included in any netting calculation, if Seller and Buyer are each required to pay an amount in the same month to the other, such amounts shall be netted, and the Party owing the greater aggregate amount shall pay to the other Party any difference between the amounts owed. Each Party reserves all rights, setoffs, counterclaims and other remedies and defenses (to the extent not expressly herein waived or denied) to which such Party has or may be entitled arising from or out of this Agreement.

## ARTICLE 10.
## TRANSFER OF TITLE

Title to, and risk of loss related to, the Contract Products delivered or received hereunder shall transfer from Seller to Buyer at the Delivery Point.

## ARTICLE 11.
## TAXES

Seller shall pay or cause to be paid all taxes on or with respect to the sale of the Contract Products prior to the Delivery Point. Buyer shall pay or cause to be paid all taxes on or with respect to the purchase of the Contract Products at and after the Delivery Point. Payment of all other taxes which are enacted or become effective or are assessed with respect to the Contract Products after the Effective Date shall be governed by the terms of this Article 11.

Each Party shall use reasonable efforts to administer this Agreement and implement its provisions in accordance with the intent of the Parties to minimize the imposition of taxes. Buyer agrees to furnish Seller with all applicable tax exemption certificates and documentation where exemption from applicable taxes is claimed.

## ARTICLE 12.
## FORCE MAJEURE

In the event that either of the Parties should be delayed in, or prevented from performing or carrying out any of the agreements, covenants and obligations under this Agreement by reason of Force Majeure, then, during the pendency of such Force Majeure but for no longer period, the obligations of the Party affected by the event (other than the obligation to make payments then due or becoming due) shall be suspended to the extent of such Party's delay or inability to perform. Neither Party shall be liable to the other Party for, or on account of, any loss, damage, injury or expense (including consequential damages and cost of replacement power) resulting from, or arising out of any such delay or prevention from performing; provided, however, the pendency of such suspension will be of no greater scope and of no longer duration than is reasonably required by the Force Majeure, and the Party suffering such delay or prevention shall provide the other Party with written notice as soon as practicable after the occurrence of such event and shall take all reasonable efforts to mitigate the effects of such event of Force Majeure and to remove the cause(s) thereof. Neither Party shall be required by the forgoing provisions to settle a strike affecting it except when, according to its best judgment, such a settlement seems advisable. If Party claims a Force Majeure for a consecutive period of twelve (12) calendar months or longer and such Force Majeure excuses performance under a material provision of this Agreement, then, for so long as such Force Majeure is continuing, the Party not claiming a Force Majeure may terminate this Agreement and neither Party shall have any liability to the other as a result of such termination; provided, however, that if: (i) eight (8) or more wind turbines continue to be available for energy generation and (ii) the Force Majeure affects some, but not all, of the wind turbines at the Facility, such termination shall only apply to the affected wind turbines, and this Agreement shall remain in effect with respect to the unaffected eight (8) or more wind turbines.

## ARTICLE 13.
## EVENTS OF DEFAULT

13.1. Events of Default. For purposes of this Agreement, each of the following shall constitute an event of default ("Event of Default") with respect to a Party (the "Defaulting Party").

(a) Failure by the Defaulting Party to make, when due, any payment required under this Agreement if such failure is not remedied within five (5) Business Days after written notice of such failure is given by the other Party ("Non-Defaulting Party") and provided the payment is not the subject of a good faith dispute as described in Article 9.4.

(b) The Defaulting Party:

(i) makes a general assignment for the benefit of creditors;

(ii) files a petition or otherwise commences, authorizes or consents to the commencement of a proceeding, or cause of action, under any bankruptcy or similar law for the protection of creditors, or has any such petition filed or commenced against it that is not discharged within thirty (30) days or otherwise becomes bankrupt or insolvent (however evidenced);

(iii) is found by a court of competent jurisdiction to not be generally paying its debts as such debts become due; or

(iv) admits in writing its inability to pay its debts generally as they become due.

(c) Failure by the Defaulting Party to perform any material covenant set forth in this Agreement (other than the events that are otherwise specifically covered in this Article 13.1 as a separate Event of Default), including, but not limited to compliance with Article 8, and such failure is not excused by Force Majeure or such failure continues uncured for more than thirty (30) calendar days after written notice to such Party specifying the nature of such failure; provided, however, that in the event of an Event of Default that is not reasonably capable of cure within thirty (30) days, the Defaulting Party commences to cure such Event of Default within thirty (30) calendar days and uses Commercially Reasonable Efforts to cure such Event of Default; provided, however, that such cure period shall not exceed one hundred eighty (180) days.

(d) Any representation or warranty made by the Defaulting Party in this Agreement is not true and complete in any material respect when made unless (i) the fact, circumstance or condition that is the subject of such representation or warranty is made true within thirty (30) calendar days after written notice to such Party specifying the nature of such misrepresentation, and (ii) such cure removes any adverse affect on the other Party of such fact, circumstance or condition being otherwise than as first represented.

(e) Failure of either Party to provide or maintain credit support provided as required by Article 19.

(f) The Party consolidates or amalgamates with, or merges with or into, or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the resulting, surviving or transferee entity fails to assume all the obligations of such Party under this Agreement to which it or its predecessor was a party by operation of law or pursuant to an agreement reasonably satisfactory to the Non-Defaulting Party.

(g) The occurrence of an uncured Letter of Credit Default.

13.2. Settlement Amount.

If an Event of Default with respect to a Defaulting Party shall have occurred and be continuing, the Non-Defaulting Party shall have the right to: (i) designate a day, no earlier than the day such notice is effective and no later than 20 days after such notice is effective, as an early termination date ("Early Termination Date") to accelerate all amounts owing from the Defaulting Party to the Non-Defaulting Party, if any, and to liquidate and terminate this Agreement and (ii) withhold any payments due to the Defaulting Party under this Agreement. Notwithstanding the foregoing, the Non-Defaulting Party shall have the right to designate an Early Termination Date for this Agreement as of the date immediately preceding the institution of the relevant proceeding or the presentation of the relevant petition upon the occurrence with respect to the Defaulting Party of an Event of Default specified in Section 13.1(b). If the Non-Defaulting Party establishes an Early Termination Date, the Non-Defaulting Party shall calculate an amount equal to its Losses and Costs reduced to present value as of the Early Termination Date ("Settlement Amount"). For purposes of calculating Losses in accordance with this Article 13.2, the Non-Defaulting Party shall use the expected monthly energy output amounts shown in Appendix B in calculating the Losses attributable to Energy and Renewable Energy Certificates and shall reasonably estimate the amount of other Contract Products to be delivered and/or sold to Buyer for the remainder of the Term of Service in calculating the Losses attributable to the other Contract Products.

Notwithstanding the above language regarding the calculation of the Settlement Amount, the Non-Defaulting Party has the option of determining the Settlement Amount through the issuance of a request for proposals for the remainder of the Term of Service, which request shall be issued and processed in commercially reasonable manner. If the Non-Defaulting Party elects to issue a request for proposals to determine the Settlement Amount, then (i) the request for proposals shall only be sent to Leading Market Makers in the ISO - New England market; and (ii) the Non-Defaulting Party shall request that each such Leading Market Maker that responds to the request for proposals provide its final price on or before the date which coincides with the Early Termination Date, with such prices to be effective on the Early Termination Date. The lowest final prices of the qualified bid responses shall be used to determine the Settlement Amount for the remainder of the Term of Service. The lowest final prices of the bid responses shall be present valued for each month using the yield on US Treasury Bills or Bonds for the discount rate. If the Non-Defaulting Party elects to issue a request for proposals in order to determine the Settlement Amount, the Non-Defaulting Party shall be required to use the results of such request for proposals in making such determination and shall be required to enter into a contract as a result of the request for proposals.

The Non-Defaulting Party shall determine a single liquidated amount (the "Termination Payment") payable by the Defaulting Party to the Non-Defaulting Party by netting out from the Settlement Amount (i) any cash or other form of security then available to the Non-Defaulting Party pursuant to Article 19 and (ii) at the option of the Non-Defaulting Party (a) any amounts due to the Defaulting Party under this Agreement against (b) any amounts due to the Non-Defaulting Party under this Agreement. Notwithstanding the foregoing, all payments due and owing for the Contract Products prior to the Early Termination Date shall be made except to the extent such amounts are setoff as forth in this Article.

As soon as practicable after a liquidation, notice shall be given by the Non-Defaulting Party to the Defaulting Party of the amount of the Termination Payment. In no event shall a Termination Payment be due from the Non-Defaulting Party to the Defaulting Party. The notice shall include a written statement explaining in reasonable detail the calculation of such amount. The Termination Payment shall be made by the Defaulting Party within three (3) Business Days after such notice is effective. In connection with such payment, the Non-Defaulting Party shall have the right to draw on any cash or other form of security then available to the Non-Defaulting

Party pursuant to Article 19, or otherwise account therefor in a manner consistent with the calculation of the Termination Payment.

If the Defaulting Party disputes the Non-Defaulting Party's calculation of the Termination Payment, in whole or in part, the Defaulting Party shall, nevertheless immediately pay the total Termination Payment within three (3) Business Days after receipt of the Non-Defaulting Party's notice of such amount plus any unpaid amounts owing to the Non-Defaulting Party, and, within seven (7) Business Days of receipt of such notice, provide to the Non-Defaulting Party a detailed written explanation of the basis for such dispute. The Non-Defaulting Party shall answer any questions, within two (2) Business Days of receiving such questions, from the Defaulting Party regarding the calculation of the Termination Payment. If the dispute is resolved in favor of the Defaulting Party, the disputed amount shall be refunded within seven (7) Business Days, with interest upon such amount, calculated at the Interest Rate from the date the Termination Payment was paid to the Non-Defaulting Party until the date upon which the refund is made.

## ARTICLE 14.
## LIMITATION OF LIABILITY

EXCEPT AS SET FORTH HEREIN, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN OR IN A TRANSACTION, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

## ARTICLE 15.
## INDEMNIFICATION

15.1. Seller's Indemnity. Seller shall, to the fullest extent permitted by law, defend, indemnify and hold harmless Buyer and its directors, officers, managers, agents, employees, and contractors (the "Buyer Indemnitees") from, against and with respect to, any and all Liabilities arising out of or relating to any third party claim or action against any Buyer Indemnitees arising of the following, except to the extent caused by the negligence or willful misconduct of a Buyer Indemnitee:

(a) any inaccuracy in any representation or breach of warranty of Seller contained in this Agreement;

(b) any failure by Seller to perform or observe, or to have performed or observed, in full, any covenant, agreement or condition to be performed or observed by it under this Agreement;

(c) the design, construction, ownership, operation and maintenance of the Facility;

(d) any actual or alleged injury or death of persons or damage to property arising in connection with Seller's operation of the Facility;

(e) any payments owing by Seller to counterparties of Seller, including any expense reimbursement or other payment obligations that Seller may have in connection with the Facility; and

(f) any liabilities arising from or relating to the Facility and the Facility site, including, but not limited to, liabilities under any applicable laws addressing health, safety and the protection of the environment.

15.2. Buyer's Indemnity. Buyer shall, to the fullest extent permitted by law, defend, indemnify and hold harmless Seller and its directors, officers, managers, agents, employees, and shareholders (the "Seller Indemnitees") from, against and with respect to, any and all Liabilities arising out of or relating to any third party claim or action against any Seller Indemnitees arising out of the following, except to the extent caused by the negligence or willful misconduct of a Seller Indemnitee:

(a) any inaccuracy in any representation or breach of warranty of Buyer contained in this Agreement; and

(b) any failure by Buyer to perform or observe, or to have performed or observed, in full, any covenant, agreement or condition to be performed or observed by Buyer under this Agreement.

## ARTICLE 16.
## ASSIGNMENT

This Agreement shall inure to the benefit of, and shall be binding upon, the Parties hereto and their respective permitted successors and assigns. Neither Party shall assign or transfer, in whole or in part, this Agreement without the prior written consent of the other Party, which consent may not be unreasonably withheld. Notwithstanding the foregoing, either Party may assign the Agreement without the other Party's consent as a transfer, pledge or assignment of its rights to receive performance under a transaction as security for any financing with financial institutions provided however, that any ultimate assignee who is charged with operation of the Facility is competent to perform the assignor's obligations under the Agreement; provided, however, that in any such case, the assignor or transferor shall remain liable for all of its obligations under the Contract.

## ARTICLE 17.
## CONFIDENTIALITY

The Parties consider the terms of this Agreement to be sensitive commercial information. Accordingly, the Parties shall not disclose the terms of this Agreement to any third party unless and to the extent required to make such disclosure by action of a court or other government authority or applicable law, provided, however, each Party shall provide the other Party with prompt notice of the requirement to disclose confidential information in order to allow the other Party to seek an appropriate protective order or other remedy. The Parties shall only disclose this Agreement and other confidential information received from the other Party to (i) those of its employees, consultants, authorized representatives, and attorneys having a "need to know" in order to carry out their functions in connection with the Agreement. and (ii) to prospective lenders and investors and other prospective purchasers of energy or other products of the Facility, or Renewable Energy Certificates, which agree to maintain the confidentiality of the information disclosed. Notwithstanding the foregoing, at any time after thirty (30) days after the Effective Date, either Party may make a public announcement, or otherwise disclose, the existence and term of this Agreement, the Parties to this Agreement, and the name, location and size of the Facility.

## ARTICLE 18.
## REPRESENTATIONS AND WARRANTIES

As a material inducement to entering into this Agreement, each Party (or the Party specified, as applicable), with respect to itself, represents and warrants to the other Party as of the Effective Date:

18.1. It is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation and is qualified to conduct its business in those jurisdictions necessary to perform this Agreement.

18.2. It has or will obtain when required all regulatory authorizations necessary for it to legally perform its obligations under this Agreement and no consents of any other Party and no act of any other governmental authority is required in connection with the execution, delivery and performance of this Agreement other than those which it has or will obtain. In addition, Buyer warrants, with respect to this Agreement, that all acts necessary to the valid execution, delivery and performance of this Agreement, including without limitation, competitive bidding, public notice, election, referendum, prior appropriation or other required procedures have or will be taken and performed as required under all relevant federal, state and local laws, ordinances or other regulations with which Buyer is obligated to comply.

18.3. Buyer represents and warrants that all persons making up the governing body of Buyer are the duly elected or appointed incumbents in their positions and hold such positions in good standing in accordance with all relevant federal, state and local laws, ordinances or other regulations with which Buyer is obligated to comply.

18.4. The execution, delivery and performance of this Agreement are within its powers, have been duly authorized by all necessary action and do not violate any of the terms or conditions in its governing documents or any contract to which it is a Party or any law, rule, regulation, order, writ, judgment, decree or other legal or regulatory determination applicable to it.

18.5. This Agreement constitutes a legal, valid and binding obligation of such Party enforceable against it in accordance with its terms, subject to bankruptcy, insolvency, reorganization and other laws affecting creditors' rights generally, and with regard to equitable remedies, to the discretion of the court before which proceedings to obtain same may be pending.

18.6. There are no bankruptcy, insolvency, reorganization, receivership or other proceedings pending or being contemplated by it or to its knowledge threatened against it.

18.7. Except as specified in Appendix C attached hereto, there are no suits, proceedings, judgments, rulings or orders by or before any court or any governmental authority that could materially adversely affect its ability to perform this Agreement.

18.8. Seller represents and warrants that it has the right to sell Contract Products hereunder.

18.9. Seller represents and warrants that as of the Commercial Operation Date it will be a member in good standing of the New England Power Pool.

18.10. Buyer represents and warrants that it is a member in good standing of the New England Power Pool.

18.11. Buyer represents and warrants that the Term of Agreement does not extend beyond any applicable limitation imposed by all relevant federal, state and local laws, ordinances or other regulations with which Buyer is obligated to comply or other relevant constitutional, organic or other governing documents and applicable law.

18.12. It is acting for its own account, has made its own independent decision to enter into this Agreement and as to whether this Agreement is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party hereto in so doing, and is capable of assessing the merits of, and understands and accepts, the terms, conditions and risks of this Agreement.

18.13. Seller represents that, as of the Commercial Operation Date, Seller will own the Facility and will have secured all necessary rights to or in any Material Contract

18.14. Buyer warrants that it has the capacity to be sued by Seller for disputes arising under this Agreement. Buyer further warrants that in any contract action brought by Seller, whether in law or equity, to enforce Buyer's obligations under this Agreement, Buyer shall not raise sovereign immunity as a defense to such contract action.

## ARTICLE 19.
## CREDIT SUPPORT

19.1. Seller Credit Support

(a) Within five (5) Business Days after the date on which the construction financing for the Facility is closed and all conditions to disbursement of funds have been satisfied ("Closing Date"), Seller shall provide Rubin and Rudman LLP with a Letter of Credit issued by a Qualified Institution, substantially in the form attached hereto as Appendix A for the collective benefit of Buyer, and the Other Purchasers as buyers of the output from the Facility under the same terms and conditions as set forth in this Agreement. The Letter of Credit or a replacement Letter of Credit shall be maintained in the following amounts: $2,000,000 from up to five Business Days after the Closing Date until December 31, 2012; $1,866,667 from January 1, 2013 until December 31, 2013; $1,733,334 from January 1, 2014 until December 31, 2014; $1,600,001 from January 1, 2015 until December 31, 2015; $1,466,668 from January 1, 2016 until December 31, 2016; $1,333,335 from January 1, 2017 until December 31, 2017; $1,200,002 from January 1, 2018 until December 31, 2018; $1,066,669 from January 1, 2019 until December 31, 2019; $933,336 from January 1, 2020 until December 31, 2020; $800,003 from January 1, 2021 until December 31, 2021; $666,670 from January 1, 2022 until December 31, 2022; $533,337 from January 1, 2023 until December 31, 2023; $400,004 from January 1, 2024 until December 31, 2024; $266,671 from January 1, 2025 until the day fifteen years following the Commercial Operation Date. The amount maintained for the benefit of the Buyer shall be equal to the Contract Products percent multiplied by the applicable amount of the Letter of Credit set forth in the prior sentence ("Seller's Credit Support Amount"). The Seller shall be required to maintain the Seller's Credit Support Amount until such time as the Seller obtains an Investment Grade Credit Rating at which time the Seller's Credit Support Amount shall be cancelled and returned to the Seller. However, if at any time after the Seller obtains an Investment Grade Credit Rating, (a) the Credit Rating of Seller is lowered by S&P below BBB- and/or by Moody's below Baa3, as applicable, or (b) Seller fails to maintain a Credit Rating with at least one of S&P or Moody's and such failure is continuing, then Seller shall be required to provide the Seller's Credit Support Amount to Buyer within five (5) Business Days of a request by Buyer to be held as security for Seller's obligations under this Agreement.

(b) For purposes hereof, it shall be a "Letter of Credit Default" with respect to any Letter of Credit, upon the occurrence of any of the following events: (i) the Qualified Institution shall fail to maintain a Credit Rating of at least ("A-") by S&P and ("A3") by Moody's, (ii) the Qualified Institution shall fail to comply with or perform its obligations under such Letter of Credit if such failure shall be continuing after the lapse of any applicable grace period; (iii) the Qualified Institution shall disaffirm, disclaim, repudiate or reject, in whole or in part, or challenge the validity of such Letter of Credit; (iv) such Letter of Credit shall fail or cease to be in full force and effect at any time during the Term of Agreement; (v) any event analogous to an event specified in Articles 13.1(b) or 13.1(c) of this Agreement shall occur with respect to the Qualified Institution; or (vi) the Seller or the Qualified Institution shall fail to cause the renewal or replacement of the Letter of Credit to the Buyer at least thirty (30) days prior to the expiration of such Letter of Credit; provided, however, that no Letter of Credit Default shall occur in any event with respect to a Letter of Credit after the time such Letter of Credit is required to be canceled or returned to the Seller in accordance with the terms of this Agreement. If a Letter of Credit Default occurs, then the Party which has applied for such Letter of Credit shall have five Business Days to: (i) cure the event(s) causing the Letter of Credit Default; (ii) replace the Letter of Credit with a substitute Letter of Credit in the same amount as the Letter of Credit that is subject to the Letter of Credit Default and in a form reasonably acceptable to recipient of such Letter of Credit (either Rubin and Rudman LLP or Seller, as applicable) (for this paragraph only, "Substitute Letter of Credit"); or (iii) post Funds in the same amount as the Letter of Credit that is subject to the Letter of Credit Default. Any failure to cure the event(s) causing the Letter of Credit Default or to provide a Substitute Letter of Credit or Funds within five Business Days after the event(s) leading to the Letter of Credit Default shall be an Event of Default under Article 13.1(g).

19.2. Buyer Credit Support.

(a) Within five (5) Business Days after the Closing Date, Buyer shall provide Seller with evidence of an Investment Grade Credit Rating pertaining to it of S&P BBB- and/or Moody's Baa3 or better. If this is not provided, then within five (5) days after the Closing Date, Buyer shall provide Seller with cash or a Letter of Credit issued by a Qualified Institution, substantially in the form attached hereto as Appendix A. The cash, Letter of Credit or a replacement Letter of Credit shall be maintained in an amount equal to the Seller's Credit Support Amount multiplied by the Contract Products percent ("Buyer's Credit Support Amount"). The Buyer shall be required to maintain the Buyer's Credit Support Amount until such time as the Buyer obtains an Investment Grade Credit Rating at which time the Buyer's Credit Support Amount shall be cancelled and returned to the Buyer if such credit support amount was provided in the form of a Letter of Credit and shall be returned to the Buyer if such credit support amount was provided in the form of cash. However, if at any time after the Buyer obtains an Investment Grade Credit Rating, (a) the Credit Rating of Buyer is lowered by S&P below BBB- and/or by Moody's below Baa3, as applicable, or (b) Buyer fails to maintain a Credit Rating with at least one of S&P or Moody's and such failure is continuing, then Buyer shall be required to provide the Buyer's Credit Support Amount to Seller within five (5) Business Days of a request by Seller to be held as security for Buyer's obligations under this Agreement.

## ARTICLE 20.
## OPERATIONS COMMUNICATION

Commencing on the Effective Date, the Seller shall provide to Buyer inputs, as requested, concerning the quarterly performance reports, and notification of major plant incidents, including scheduled and unscheduled outages, and operating limitations. The Seller shall meet with the Buyer at a time and place that is mutually agreed to between the Buyer and the Seller. The Seller shall not be required to meet with the Buyer more than once every six months. The Buyer shall be notified regarding any decision or issue having a material impact on the capacity, availability or dispatch of the Facility. Seller shall retain final decision authority on all matters relating to the Facility. Seller shall use commercially reasonable efforts to provide the Buyer with a non-binding day ahead forecast of hourly production on each non-holiday weekday by 10:30 EPT.

## ARTICLE 21.
## DISPUTE RESOLUTION

21.1. Any disputes between the Parties under this Agreement shall be referred to the senior executives of the Buyer and Seller for resolution on an informal basis as promptly as practicable ("Informal Dispute Resolution"). In the event that the senior executives are unable to resolve the dispute within thirty (30) days, or such other period as the Parties may jointly agree upon, the Parties shall be able to pursue all available legal remedies, including, but not limited to, arbitration as set forth in Article 21.2. The Parties shall not be required to engage in Informal Dispute Resolution with respect to disputes concerning Article 13 or Article 15, and may immediately pursue all available legal remedies, including, but not limited to, arbitration as set forth in Article 21.2, with respect to such disputes.

21.2. Once the Parties have satisfied the requirements of Article 21.1, then any dispute, need of interpretation, claim, counterclaim, demand, cause of action, or other controversy arising out of or relating to this Agreement or the relationship established by this Agreement, any provision hereof, the alleged breach thereof, or in any way relating to the subject matter of this Agreement, involving the Parties and/or their respective representatives (for purposes of this Article 21.2 only, collectively, the "Claims"), whether such Claims sound in contract, tort, or otherwise, at law or in equity, under state or federal law, whether provided by statute or the common law, for damages or any other relief, may, if the Parties mutually agree, be resolved by binding arbitration in accordance with this Article 21.2. Arbitration shall be conducted in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("AAA") as the same may be in effect from time to time to the extent not in conflict with this Article 21.2. One arbitrator shall be appointed, who shall have at least eight years' professional experience in electrical energy-related transactions; shall not have been previously employed by either Party; and shall not have a direct or indirect interest in either Party or in the subject matter of the arbitration. The validity, construction, and interpretation of this agreement to arbitrate, and all procedural aspects of the arbitration conducted pursuant hereto shall be decided by the arbitrator. In deciding the substance of the Parties' claims, the arbitrator shall refer to the governing law, shall permit and supervise the conduct of discovery among the Parties in accordance with the Federal Rules of Civil Procedure (unless otherwise agreed by the Parties in a particular arbitration), and shall have the authority to determine summarily any matter in dispute where there is no genuine issue of material fact and a Party is entitled to prevail as a matter of law. The arbitrator shall have no authority to award consequential, multiple, exemplary or punitive damages of any type under any circumstances whether or not such damages may be available under state or federal law, or under the Commercial Arbitration Rules of the AAA, the Parties hereby waiving their rights, if any, to recover any such damages. The arbitration proceeding shall be conducted in Portland, Maine, or in any other mutually agreed upon location and governed by Maine law, notwithstanding any laws requiring the application of the laws of another state. To the fullest extent permitted by law, any arbitration proceeding and the arbitrator's award shall be maintained in confidence by the Parties. Judgment on the award rendered by the arbitrator may be entered in any court having jurisdiction thereof. It is agreed that the arbitrator shall not have the power to amend or to add to this Agreement, and further that the arbitrator shall not have the authority to make rulings of law other than rulings as to the interpretation of this Agreement.

## ARTICLE 22.
## GENERAL PROVISIONS

22.1. Waivers. Any waiver at any time by any Party of its rights with respect to the other Party or with respect to any matter arising in connection with this Agreement shall not be considered a waiver with respect to any other prior or subsequent default or matter.

22.2. Any notice, demand, request, consent, approval, confirmation, communication, or statement which is required or permitted under this Agreement, shall be in writing, except as otherwise provided, and shall be given or delivered by personal service, telecopy, telegram, Federal Express or comparable overnight delivery service, or by deposit in any United States Post Office, postage prepaid, by registered or certified mail, addressed to the Party at the address set forth below. Changes in such address shall be made by notice similarly given.

Notices to Buyer shall be sent to:

Pascoag Utility District
253 Pascoag Main Street
PO Box 854
Pascoag, RI
02859
Attn. General Manager: Theodore G. Garille
Phone: (401) 568-6222
Fax: (401) 568-0066
Email: tgarille@pud-ri.org

With a copy to:

Energy New England LLC
100 Foxborough Boulevard, Suite 110
Foxborough, MA 02035
Attn. Timothy Hebert
Phone: (508) 698-1219
Fax: (508) 698-0222

Email: Thebert@energynewengland.com ; accounting@energynewengland.com

Notices to Seller shall be sent to:

Spruce Mountain Wind, LLC
549 South Street, Building 19
Quincy, MA 02169
Attn: Andrew Goldberg
Phone: 617-503-5640
Fax: 617-890-0606
Email: agoldberg@patriotrenewables.com

With a copy to:

Spruce Mountain Wind, LLC
549 South Street, Building 19
Quincy, MA 02169
Attn: Todd Presson
Phone: 617-503-5435
Fax: 617-890-0606
Email: tpresson@patriotrenewables.com

Notices shall be deemed to have been received, and shall be effective, upon receipt. Notices of changes of address by either Party shall be made in writing no later than ten (10) days prior to the effective date of such change; provided, however, that any failure hereof shall not be deemed an event of default or other grounds for termination of the Agreement.

22.3. Governing Law and Waiver of Jury Trial. All disputes arising out of the performance or non-performance under this Agreement shall be construed in accordance with the laws of the State of Maine, notwithstanding any laws requiring the application of the laws of another state. Each Party agrees to waive all rights to a trial by jury in the event of litigation to resolve any disputes hereunder.

22.4. Headings Not to Affect Meaning. The descriptive headings used for the various Articles and sections herein have been inserted for convenience and reference only and shall in no way affect the meaning or interpretation, or modify or restrict any of the terms and provisions hereof.

22.5. No Consent to Violation of Law. Nothing contained herein shall be construed to constitute consent or acquiescence by either Party to any action of the other Party which violates the laws of the United States as those provisions may be amended, supplemented or superseded, or which violates any other law or regulation, or any order, judgment or decree of any court or governmental authority of competent jurisdiction.

22.6. No Dedication of Facilities. Any undertakings or commitments by one Party to the other Party under this Agreement shall not constitute the dedication of the system or any portion thereof of any Party to the public or to the other Party.

22.7. Relationship to the Parties. Nothing contained in this Agreement shall be construed to create an association, joint venture, partnership or any other type of entity or relationship between Seller and Buyer, or between either or both of them and any other Party.

22.8. Third-Party Beneficiaries. This Agreement is intended solely for the benefit of the Parties hereto, and nothing therein will be construed to create any duty to, or standard of care with reference to, or any liability to, any person not a Party hereto.

22.9. Entire Agreement. This Agreement and the attached appendices constitute the entire agreement between the Parties and parol or extrinsic evidence shall not be used to vary or contradict the express terms of this Agreement.

22.10. Records. The Parties shall keep (or as necessary cause to be kept by their respective agents) for a period of at least two (2) years such records as may be needed to afford a clear history of all deliveries of Energy pursuant to this Agreement. For any matters in dispute, the Parties shall keep the records related to such matters until the dispute is ended. In maintaining or causing to be maintained such records, the Parties shall effect such segregation and allocation as may be needed to properly bill delivery of Energy pursuant to this Agreement.

22.11. Audit. Not more than once each calendar quarter, each Party or any third party representative of a Party shall have the right, at its sole expense, to examine the records of the other Party relating to this Agreement during normal business hours upon reasonable notice to the extent necessary to verify any invoice or amounts due and payable pursuant to this Agreement.

22.12. Amendment. This Agreement shall be amended or modified only by the mutual written agreement of both Seller and Buyer.

22.13. Counterparts. This Agreement may be executed in any number of counterparts, each of which shall be an original, but all of which together shall constitute one instrument.

22.14. Forward Contract. The Parties acknowledge and agree that this Agreement is a "forward contract" within the meaning of the Bankruptcy Code, and that the Parties are acting as "forward contract merchants" by entering into the Agreement.

22.15. Material Adverse Change. If the federal government, the State of Rhode Island, or ISO-New England, Inc. adopts, enacts, or otherwise imposes a new law, rule or regulation which either makes a Party's performance under this Agreement unlawful, or makes this Agreement unenforceable and such governmental action does not constitute a Force Majeure event under Article 12 of this Agreement, the Parties shall negotiate in good faith to amend the terms of this Agreement and to determine the appropriate changes, if any, so that the Party affected by such change in law or regulation is able to lawfully perform its obligations without materially adversely affecting the financial benefit hereunder to the other Party. If the Parties are unable to reach agreement on such an amendment, then the Parties may pursue any legal or equitable remedies that may be available.

22.16. Severability. In the event that any provision of this Agreement is deemed unlawful or unenforceable, the remaining provisions shall remain in full force and effect; provided that (1) the material purpose thereof can be lawfully effectuated; and (2) the economics underlying this Agreement remain substantially the same.

22.17. Further Assurances. Buyer acknowledges that Seller intends to finance the acquisition and construction of the Facility, and may in the future refinance such financing, with funds to be provided, in whole or in part, by lenders and equity investors, some or all of which are yet to be identified. As reasonably necessary to accommodate such financing or refinancing, Buyer shall provide such information and documentation as may be reasonably requested by any actual or prospective lender or equity investor, including (i) financial statements, and evidence of authority and incumbency of persons executing this Agreement; (ii) a certificate from the manager or an officer confirming the enforceability of this Agreement against Buyer and the accuracy of the representations of Buyer set forth in Sections 18.1 through 18.5, 18.10 and 18.11, and addressing such other matters as may be reasonably requested by any such actual or prospective lender or equity investor, (iii) a consent to the collateral assignment of this Agreement to any such actual or prospective lender or equity investor containing such terms and provisions as may be reasonably requested by such actual or prospective lender or equity investor, including a right to cure Seller defaults provided such consent does not impair or diminish Buyer's rights hereunder, and (iv) any other consents, estoppel certificates or other documents reasonably required in connection with the financing of the Facility provided such other consents, estoppel certificates or other documents do not impair or diminish Buyer's rights hereunder. Seller shall reimburse Buyer for its legal fees resulting from compliance with this Section 22.17.

22.18. Bankruptcy Code References. The payment of the Settlement Amount constitutes a "margin payment", and the Termination Payment constitutes a "settlement payment" and/or a "transfer" under the Bankruptcy Code and for purposes of determining the Termination Payment by the Non-Defaulting Party, the netting out from the Settlement Amount of the Buyer's or Seller's Letter of Credit, as applicable, held by the Non-Defaulting Party under Article 19 herein shall constitute a "setoff or net out of termination values or payment amounts" under the Bankruptcy Code. "Bankruptcy Code" shall mean the U.S. Bankruptcy Code, 11 U.S.C. Sec. 101 et. Seq., as such may be amended from time to time.

## ARTICLE 23.
## COMMISSION REVIEW

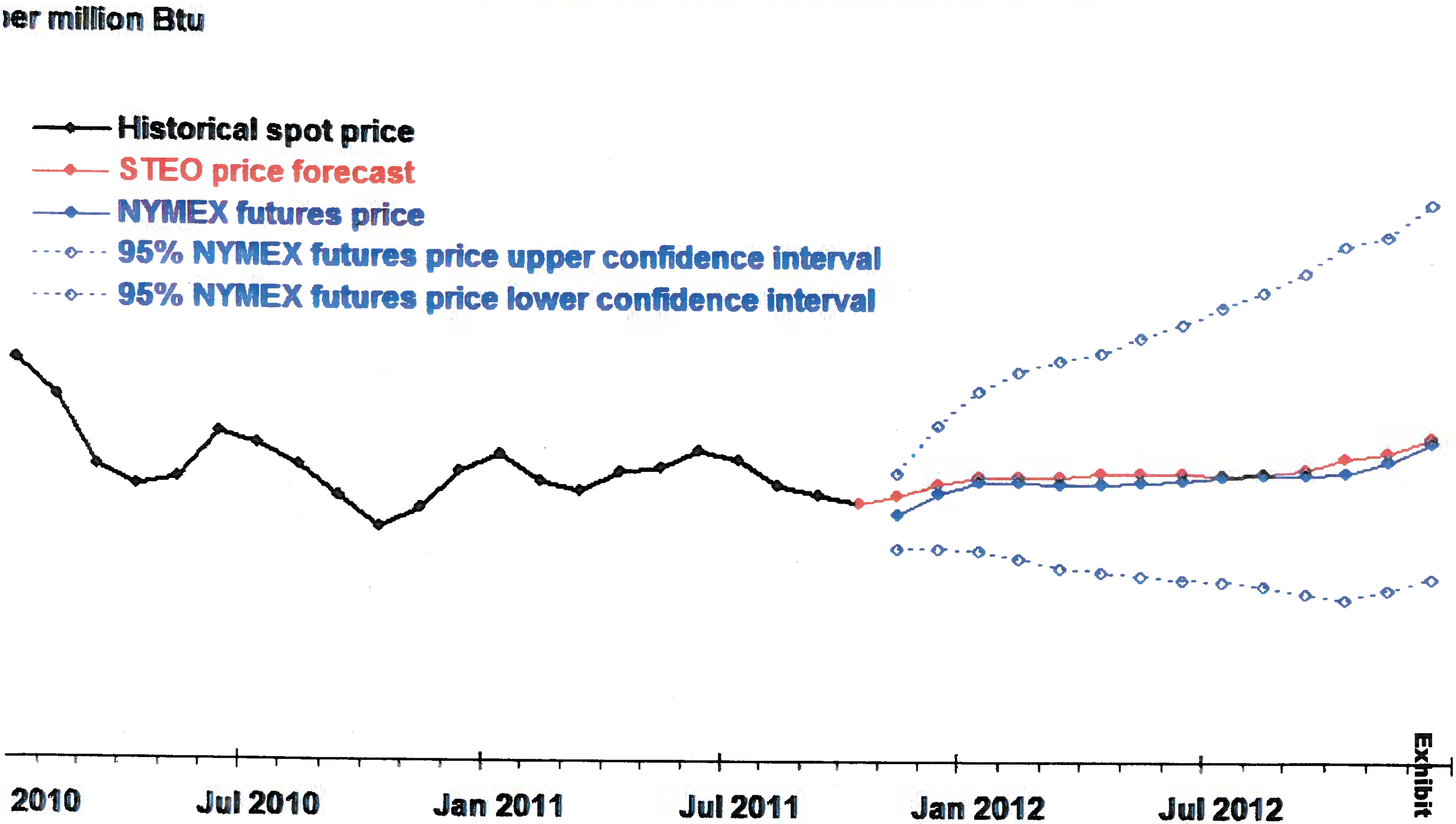
(a) Neither Party shall seek to change or amend this Agreement in any way through making application to the Maine Public Utilities Commission or the Federal Energy Regulatory Commission (or to any other government agency or authority), and this Agreement shall not be subject to change through unilateral application by either Party under Sections 205 and 206 of the Federal Power Act (or pursuant to any other provision of law). Each Party hereby irrevocably waives the right to seek any change or to support any application or complaint or other legislative, judicial or regulatory action made seeking a change in the rates or a change in the terms and conditions of this Agreement, absent the mutual agreement of the Parties.

(b) Absent the agreement of both Parties to the proposed change, the standard of review for changes to this Agreement proposed by either Party, a non-party or the Federal Energy Regulatory Commission acting sua sponte shall be the "public interest" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Services Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) (the "Mobile-Sierra" doctrine).

Agreed to as of the date set forth above.

| SELLER | BUYER |
|---|---|
| SPRUCE MOUNTAIN WIND, LLC | Pascoag Utility District |
| By:___________________________ | By:___________________________ |
| Name: Jay M. Cashman | Name: Theodore G. Garille |
| Title: | Title: General Manager |

# Henry Hub Natural Gas Price




e: Confidence interval derived from options market information for the 5 trading days ending October 6, 201
tervals not calculated for months with sparse trading in "near-the-money" options contracts

Short-Term Energy Outlook, October 2011

Exhibit 3-MRK

**Exhibit 4-MRK**

EXECUTION

## Confirmation Letter

This Confirmation (the "Confirmation") shall confirm the agreement reached on May 11, 2011 (the "Trade Date") between Constellation Energy Commodities Group, Inc. ("Constellation") and Pascoag Utility District, Rhode Island ("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 as of November 8, 2010 (the "Master Agreement") between Constellation and Pascoag and constitutes part of and is subject to the terms and provisions of such Master Agreement.

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

1.4 "Constellation Estimated Load" shall have the meaning set forth in Section 3.3

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

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

1.7 "HE" shall mean hour ending.

1.8 "Hedged Percentage" shall mean one hundred percent (100%) in calendar year 2012, eighty percent (80%) in calendar year 2013 and seventy-five percent (75%) in calendar year 2014 of the gross hourly Energy requirements of Pascoag's ratepayers located in Pascoag's service territory as of the Trade Date.

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

1.10 "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.

1.11 "Load" means the Energy that Constellation shall make available to Pascoag hourly in order to serve the Hedged Percentage, as represented by 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 Energy requirements related to (i) any wholesale or aggregation transaction to which Pascoag is a Party; (ii) any acquisition, annexation, merger, joint venture, partnership, or other similar transaction that Pascoag may undertake; 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, Constellation and Pascoag agree to meet to discuss whether changes may be made to this Confirmation to address how Pascoag's additional load obligation can be met under this Confirmation; provided however, neither Party shall be required to accept a change with which it, in its sole judgment, disagrees.

1.12 "Load Cap" shall mean 14 MW.

1.13 "Load Following Energy" shall mean that Constellation shall provide Energy to Pascoag to serve the Load by scheduling an amount of Energy during On-Peak Hours, Off-Peak Hours and 2x16 Hours on the day after each Operating Day that is equal to the amount of Load for each hour of such Operating Day.

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

1.15 "MW" shall mean megawatts.

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

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

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

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

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

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

1.22 "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.

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

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

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

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

2. Term. Constellation's obligation to schedule and sell Energy, as defined in this Confirmation, and Pascoag's obligation to confirm and pay for Energy shall become effective on HE 0100 EPT, on January 1, 2012 and shall remain in effect through HE 2400, EPT, on December 31, 2014 (the "Term") unless earlier terminated pursuant to this Confirmation ("Term of Service"); 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 Term, Constellation shall schedule and sell and Pascoag shall confirm and purchase 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, 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. Pascoag shall confirm or cause the confirmation of the scheduling of Energy by Constellation in accordance with ISO-NE Rules.

3.3 Scheduling of Energy. Constellation shall schedule Load Following Energy to Pascoag in accordance with Section 3.3.1. If Constellation does not know the actual amount of the RTLO in time to schedule the Energy on the day after the Operating Day, Constellation 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 "Constellation Estimated Load"). If Pascoag's actual Load differs from the Constellation Estimated Load, Constellation 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, Constellation shall schedule Energy by submitting one IBT Container for such Operating Day.

3.3.1 Load Calculation. Constellation 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 Constellation Estimated Load. In the event that Constellation schedules an amount of Energy that is different than the amount of Load in any hour on an Operating Day, Constellation 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 ISO-NE Rules for the hours when Constellation 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 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. Constellation shall schedule all deliveries of Energy to the Massachusetts Trading Hub (ISO-NE Node #4000) (the "Delivery Point"). Constellation shall bear all costs and losses of supplying Energy hereunder to the Delivery Point and Pascoag shall bear all costs and losses at and after the Delivery Point. Title to all Energy shall pass at the Delivery Point.

5. Purchase Price. Pascoag shall pay Constellation, each month during the 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"). The Purchase Price shall not be subject to adjustment or change except as set forth herein.

6. Load Growth.

6.1 Changes in Service Territory; Additional Customers; Load Cap. Notwithstanding anything to the contrary in this Confirmation, Constellation shall not be obligated to schedule and deliver Load Following Energy for any changes to the Load resulting from any excess Load over the Load Cap. To the extent that Pascoag does incur such an additional load obligation in excess of the Load Cap, Constellation and Pascoag agree to meet to discuss whether changes may be made to this Confirmation to address how Pascoag's additional load obligation can be met under this Confirmation; provided however, neither Constellation nor Pascoag shall be required to accept a change with which it, in its sole judgment, disagrees.

6.2 Involuntary Demand Response. If Pascoag becomes subject to any load interruption or demand-side management program (collectively, "DR Programs") imposed by applicable law or ISO-NE that affects Pascoag's Load then Pascoag shall provide Constellation 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. Constellation and Pascoag agree to meet to discuss whether changes may be made to the prices set forth in Exhibit A; provided however, neither Party shall be required to accept a change with which it, in its sole judgment, disagrees. In the event that Pascoag and Constellation cannot agree to such changes, then either Party may terminate this Confirmation upon 45 days' prior written notice without any further action.

6.3 Voluntary Demand Response. Prior to Pascoag instituting any DR Program, Pascoag will provide at least 60 days advance written notice to Constellation 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 Constellation 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 Constellation 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.

CONSTELLATION ENERGY COMMODITIES GROUP, INC.

MB

By: Bryan P. Wright
Its: Controller

PASCOAG UTILITY DISTRICT, RHODE ISLAND

By: Michael Kirkwood
Its: General Manager / CEO

## SCHEDULE I

## Fixed Volumes

| Pascoag's "FIXED" Supply Volumes for 2012/2013/2014 | | | |
|---|---|---|---|
| **Month** | **On-Peak** | **Off-Peak** | **2x16** |
| January | 3.564 | 3.414 | 3.564 |
| February | 3.571 | 3.441 | 3.591 |
| March | 3.573 | 3.453 | 3.603 |
| April | 3.622 | 3.482 | 3.632 |
| May | 3.563 | 3.423 | 3.573 |
| June | 3.461 | 3.321 | 3.471 |
| July | 3.398 | 3.248 | 3.398 |
| August | 3.383 | 3.253 | 3.403 |
| September | 3.404 | 3.274 | 3.424 |
| October | 3.500 | 3.350 | 3.500 |
| November | 3.550 | 3.420 | 3.570 |
| December | 3.585 | 3.435 | 3.585 |

## EXHIBIT A

## Pricing

| Monthly Pricing for 2012/2013/2014 | | | |
|---|---|---|---|
| **Month** | **On-Peak** | **Off-Peak** | **2x16** |
| January | $59.90 | $59.90 | $59.90 |
| February | $59.90 | $59.90 | $59.90 |
| March | $59.90 | $59.90 | $59.90 |
| April | $59.90 | $59.90 | $59.90 |
| May | $59.90 | $59.90 | $59.90 |
| June | $59.90 | $59.90 | $59.90 |
| July | $59.90 | $59.90 | $59.90 |
| August | $59.90 | $59.90 | $59.90 |
| September | $59.90 | $59.90 | $59.90 |
| October | $59.90 | $59.90 | $59.90 |
| November | $59.90 | $59.90 | $59.90 |
| December | $59.90 | $59.90 | $59.90 |

PASCOAG
UTILITY DISTRICT

Pascoag Electric • Pascoag Water

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Phone: 401-568-6222
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# Index

## Testimony and Exhibits of Judith R. Allaire

**Testimony of Judith R. Allaire, Assistant General Manager**

**Q. Please provide a summary of the actual reconciliation of factors for the period ending December 31, 2011.**

**A.** As of the filing date, this submittal contains actual expenses and revenue through September 2011. The fourth quarter (October through December) is based on revised estimates provided by Energy New England ("ENE"). Table 1, below, outlines the adjustments to the fourth quarter:

| | Table 1<br>**Fourth Quarter 2011 Budget Assumptions** | |
|---|---|---|
| **MWH**<br>13,746<br>13,746 | **Total Costs**<br>Original Budget $1,389,460<br>Revised Budget $1,377,625<br>Total Decrease ($ 11,835) | **$/MWH**<br>$101.08<br>$100.22 |
| | **Details of Decrease** | |
| Adjustments to Spruce Mtn. Energy | Removed October generation | ($15,263) |
| Adjustments to Seabrook<br>October - December<br>October | Reduced price to $9/MWH from $9.59/MWH<br>Reduced October's capacity to 50% due to unscheduled outage | ($ 6,001) |
| Adjust ENE fee | From $6,200/month to $6,386/month | $ 558 |
| Adjust National Grid | DAF from $9,510/month to $6,590/month | ($ 8,760) |
| Increase Purchases | From ISO spot market | $ 14,316 |
| Increase Purchases | From BELD | $ 3,314 |
| | | |
| **Total Adjustments** | | **($11,836)** |

Based on these adjustments, the projected reconciliation at December 31, 2011 is estimated to be an over collection of $393,002. For a summary of this over collection, please see ***Testimony Exhibit 1-JRA***. This does not include the $200,000 that Pascoag encumbered at year-end 2010. At that time, Commission approved Pascoag's request to put $200,000 of last year's over collection in its Purchased Power Restricted Fund Account ("PPRF") to be used for Pascoag's participation in a Special Purpose

Entity ("SPE") Project with several other public power systems investigating the feasibility of purchasing output from a generating plant located in Northern Massachusetts. In the event that project did not go forward, Pascoag agreed that those funds would be used to stabilize customer fuel rates in the future. Later in this testimony, and in the testimony of Mr. Kirkwood, these encumbered funds will be addressed. Table 2 details the expected over collection:

| Table 2 | **Forecast at December 31, 2011** |
|---|---|
| SOS | $251,435 |
| Transition | $ 22,983 |
| Transmission | $118,584 |
| | |
| **Total**<br>**(See Schedule C1 – C4, Book 2)** | **$393,002**<br>**(Forecast based on actual expenses through September and Fourth Quarter Estimates)** |

**Q. Will Pascoag be able to provide an update on the actual expenses at, or prior to, the hearing?**

**A.** Yes. All of the October power invoices should be received by November 30, 2011, so Pascoag will be able to provide actual October expenses and revenues 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 Division in its required monthly updates.

**Q. Can you provide a brief overview of any items that impacted this filing that would have contributed to the over collection?**

**A.** As in past years, NYPA interruptible energy proves to be beneficial to Pascoag's customers. In 2011, Pascoag received interruptible energy each month through September. We expect this trend to continue for the last quarter of the year. Although this has been a trend, forecasting this entitlement in 2012 continues on the conservative side.

In 2011, sales to customers were higher than forecast, resulting in higher revenue. In July, Pascoag hit a new all time peak – almost 12.8 MW's. This is up from last year's peak demand of 12.3 MW's. This is due in part to the higher than normal temperatures during that month. ***Testimony Exhibit 2-JRA,*** attached with this filing, is the summary of peak demand activity

Pascoag continues to use a three-year average for its forecast of sales to customers. This tends to "even out" any high or low periods of consumption.

The MMWEC Excess Fund Surplus Credit for 2010/2011 was $95,157. This was spread over an eleven month payback period and resulted in a monthly credit on the Project 6 invoice of $8,650. For 2011/2012, the Surplus Fund credit is expected to be $77,690. This year, MMWEC changed its payback period to ten months. Beginning in August 2011, and continuing through May 2012, that monthly credit will be $7,769. A summary of the MMWEC Surplus Fund credit is attached as ***Testimony Exhibit 3-JRA.***

In addition, Pascoag's actual purchase power costs are lower than in ENE's 2011 original and revised forecast. This is highlighted below in Table 3. This reduced the cost per MWH from $101.14 in the forecast to $97.63 per MWH for the actual reconciliation.

| Table 3 | **Purchase Power Expense** | **Difference** |
|---|---|---|
| | | |
| 2011 Actual Cost | $5,454,015 | |
| 2011 Original Forecast | $5,593,165 | ($139,150) |
| 2011 Revised Fourth Quarter Forecast | $5,581,330 | ($127,315) |

All of these items impact the over collection at year-end 2011. ***Testimony Exhibit 4-JRA*** is the Reconciliation of Forecast to Actual.

**Q. Please provide forecast power and transmission expense for 2012, as well as the assumptions to calculate the forecast.**

**A.** The 2012 forecast contains several budget assumptions. The 2012 forecast is for a total of $5,175,971, or approximately $417,000 lower than 2011's original forecast. The largest contributor to this reduction is a new load-following product from Constellation that replaces the Dominion and Braintree Electric Light Department ("BELD") contracts. Mr. Kirkwood will address the details of this new three-year contract, but briefly, it allows Pascoag to purchase only the energy that it needs – the amount is dependent on Pascoag's power requirements.

The major items contributing to the decreased budget are summarized below:

1. Adjustments to NYPA Demand Rate and Capacity Factor;
2. Adjustments to Seabrook in Fixed Costs, Capacity Factor, and Surplus Fund Credit;
3. Adjustment in ENE's monthly Fee
4. Replacement of the 3 MW around-the-clock purchase from Dominion @ $79.50 and BELD Peaking Load @ $59 with the Balancing Purchase from Constellation at $59.90;
5. The new wind entitlement – Spruce Mountain for the full year in 2012;
6. Increases to ISO for off-peak power;
7. Adjustments to ISO expenses;
8. Adjustments to OATT RNS to $5.94/kW-mo for January – May and forecast $6.65/kW-mo for July – December;
9. And, a reduction in National Grid's DAF charges.

These items are detailed in ***Testimony Exhibit 5-JRA, "2012 Budget Assumptions"***.

**Q. Please update the Commission on Pascoag's PPRF.**

**A.** In December 2009, Commission approved Pascoag's request to increase its PPRF to $500,000. Pascoag complied with that order in January 2010, when it transferred $200,000 from the cumulative over collection into the PPRF account.

In December 2010, Commission approved Pascoag's request to retain $200,000 from the over collection and to hold it in abeyance in the PPRF for use if the Special Purpose Entity Project went forward. If that project did not come to fruition, Pascoag agreed that those funds would be used to offset future rate increases. That brought the balance in the PPRF to $699,276.

In April 2011, Pascoag transferred $100,000 from the PPRF to its operating account to meet outstanding power bills. This was done with Division's review and consent. In May, the District replaced $50,000; in October $30,000 was transferred back to the PPRF; and by December, the District will complete the reimbursement. A summary of activity to the PPRF account is included as ***Testimony Exhibit 6-JRA.***

This account, as well as the Restricted Fund for Capital Projects and Debt Service, had a maturity date of October 31, 2011. After reviewing various options, including long and short term investments, District management decided to roll over both accounts into another eighteen-month Repurchase Agreement. Interest rate for the new eighteen-month period is .8%. This is the best interest rate Pascoag could negotiate – a thirty-day roll over would offer .55%. These Repurchase Agreements are fully collateralized. Pascoag has ready access to both these accounts, both for deposits and withdrawals as necessary.

**Q. Please provide an update on the District's Restricted Fund for Capital Projects and Debt Service, and update the Commission on Pascoag's request to only partially fund this account in 2011 and 2012.**

**A.** For the first time since its inception in 2004, Pascoag realized that in 2011 it would not be able to fund this account with the annual mandated amount of $376,000. In September, Pascoag requested that Commission waive its order requiring this annual funding. The District believed that doing this earlier in the year, rather than at the hearing, would give all parties the opportunity to review the issue.

To-date in 2011, Pascoag has funded $185,000. It was Pascoag's request that this be capped as the amended limit for 2011. Looking forward to 2012, Pascoag reduced its Capital Projects budget to a level of $62,500, and requested that that be the required funding limit for the Restricted Fund in that year.

Pascoag responded to data requests by both Commission and Division on this request, and they are included as ***Testimony Exhibit 7-JRA "Data Requests".***

A summary of activity in the Restricted Fund Account – Capital Projects and Debt Service is included as ***Testimony Exhibit 8-JRA.***

**<u>Q. Does Pascoag have any other issues that impact its financial position? And, if so, how does the District plan to address these issues?</u>**

**A.** A faltering economic recovery, slow collection of Account Receivable balances, foreclosures and bankruptcies all impact the District's financial picture. In addition, and adding to the problem, is that the District's last Cost of Service Rate Case was in 2003/2004, and operating costs have increased since that period that are not covered in base rate collection.

This year, the District expects write off balances to be higher than in the past. The average annual write off balance amount has been approximately $21,000.

***Testimony Exhibit 9-JRA*** details a summary of the District's outstanding accounts payable and account receivable balances. ***Testimony Exhibit 10-JRA*** is a monthly summary of the District's cash flow position.

Pascoag realizes that in order to address the financial concerns, it will be necessary to file a comprehensive Cost of Service Study. To that end, in mid-October, Pascoag sent out a Request For Proposals ("RFP") to several consultants. This schedule allows time for pre-bid meetings, questions, clarifications, and presentations before the anticipated bid award date of December 15, 2011. It is Pascoag's intent to submit the complete Cost of Service Study and Rate Design to the Commission by mid-June 2012.

***Testimony Exhibit 11-JRA*** is the schedule/timing of events in the process. A copy of the RFP is available for review.

All of these factors are coming together when many of our customers are struggling with their own financial issues. While Pascoag realizes that a base rate adjustment is necessary, it is also sensitive to the impact on all classes of customers – Residential, Commercial, and Industrial.

**<u>Q. Does Pascoag have any recommendations on how the impact of a base rate increase can be minimized?</u>**

**A.** Yes, we have an idea that would defer a portion of the flow back in 2012, but would offer some rate relief in 2013 when the new base rates would go into effect.

Since Pascoag has a substantial over collection at year-end 2011 that will result in a rate decrease in Standard Offer, Transition, and Transmission in 2012, we are proposing that the $200,000 held in abeyance for "future rate relief" be retained by Pascoag until January 2013. This would help reduce the energy portion of the rates – specifically the Standard Offer Service – at a time when the customer charge and distribution and demand rates would be increasing. This is the $200,000 that Commission approved be encumbered for the Special Purpose Entity Project. Since that project did not come to fruition, it would be Pascoag's recommendation that this money be kept in the PPRF until 2013, and then flowed back to customers to reduce the energy portion of the electric bill.

**Q. Since the District has such a substantial over collection, and is forecasting lower energy costs in 2012, what are the rates proposed by Pascoag for Standard Offer Service, Transition, and Transmission in 2012?**

**A.** The first scenario proposed by Pascoag is to flow back the anticipated over collection of $393,000, as well as the $200,000 encumbered last year in the PPRF during 2012.

The over collection of approximately $393,000, as well as lower forecast energy costs in 2012, will result in a substantial reduction in rates for 2012. If Pascoag were to flow back the additional $200,000, it would decrease the rates even lower, resulting in the potential of "roller coaster" rates.

Based on this scenario – "Option 1" - the rates would be as outlined in Table 5, below:

| Table 5 | **Pascoag Option 1** | **Flow Back of $393,000 and $200,000 **** | |
|---|---|---|---|
| | **Current** | **Proposed** | **Difference** |
| SOS | $0.07064 | $0.05231 | ($0.01833) |
| Transition | $0.01132 | $0.01109 | ($0.00023) |
| Transmission | $0.02290 | $0.02420 | $0.00130 |
| **Total** | **$0.10486** | **$0.08760** | **($0.01726)** |
| **See Schedule H - Option 1, Book 2** | | ****Flow Back of $200,000 encumbered at 12/31/2010** | |

Under "Option 1", a residential customer using 500 kilowatt-hours would see his monthly electric bill decrease from $ 74.90 to $66.27, a decrease of $8.63, or 11.5%.

Under "Option 2", the entire over collection would be refunded, but Pascoag would retain the $200,000 encumbered last year. If this scenario were chosen, it would reduce the potential impact of a base rate increase in 2013, by reducing the energy rate portion of the customer's bill. Based on "Option 2" the rates would be as outlined in Table 6, below:

| Table 6 | **Pascoag Option 2** | **Flow Back of $393,000** | **Pascoag Retains $200,000**** |
|---|---|---|---|
| | | | |
| | Current | Proposed | Difference |
| SOS | $0.07064 | $0.05614 | ($0.01450) |
| Transition | $0.01132 | $0.01109 | ($0.00023) |
| Transmission | $0.02290 | $0.02420 | $0.00130 |
| **Total** | **$0.10486** | **$0.09143** | **($0.01343)** |
| **See Schedule H - Option 2, Book 2** | | | **** Pascoag retains the $200,000 for future rate stabilization** |

Under "Option 2", a residential customer using 500 kilowatt-hours would see his monthly bill decrease from $74.90 to $68.18, a decrease of $6.72, or 9%.

Pascoag's preference would be the approval of rates under "Option 2". It provides a substantial rate reduction in 2012. And, by allowing Pascoag to retain the $200,000 until 2013, the impact of a base rate adjustment will be somewhat mitigated.

**Q. Is Pascoag proposing a growth factor in its calculation for 2012?**

**A.** No. In its forecast for 2012 sales, and based on the three-year average, Pascoag is not forecasting any sales growth. Currently there are no residential or commercial projects anticipated.

**Q. Is this a trend that you believe will continue?**

**A.** If the economy begins a meaningful recovery, we're hopeful that growth – both residential and commercial – will pick up. However, we have been notified by the Town of Burrillville, as well as Danielle Prosciutto Industries, the DPI facility in our service territory will begin phasing out its operations in mid-2013. Obviously, this is a major concern to Pascoag, as DPI sales account for approximately twenty percent of our entire annual kilowatt-hour sales.

Mr. Kirkwood is in discussion with officials from both DPI and the Town of Burrillville, and will provide more information as it becomes available.

**Q. Does this conclude your testimony?**

**A.** Yes, it does.

| | A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|---|
| 64 | | | | | | | | **Testimony Exhibit 1-JRA** |
| 65 | | | | | | | | |
| 66 | | **<u>Combined Standard Offer, Transition Charge, and Transmission Charge</u>** | | | | | | |
| 67 | | | | | | | | |
| 68 | Forecast Cumulative Over/(Under) Collection at 12/31/2009 | | | | | | $286,833 | |
| 69 | | | | | | | | |
| 70 | Jan 2010 | Transfer to PPRF account | | | | $ (200,000) | $86,833 | Per RIPUC 12/23/09 **<u>(1)</u>** |
| 71 | | | **<u>Revenue</u>** | **<u>Expense</u>** | | **<u>Monthly</u>** | **<u>Cumulative</u>** | |
| 72 | Jan 2010 | $86,833 | $560,925 | $448,121 | | $112,803 | $199,633 | |
| 73 | Feb 2010 | $199,633 | $446,702 | $433,141 | | $13,561 | $213,194 | |
| 74 | March 2010 | $213,194 | $412,474 | $447,079 | | ($34,605) | $178,589 | |
| 75 | April 2010 | $178,589 | $478,725 | $420,739 | | $57,986 | $236,575 | |
| 76 | May 2010 | $236,575 | $373,665 | $411,079 | | ($37,414) | $199,161 | |
| 77 | June 2010 | $199,161 | $440,377 | $461,359 | | ($20,983) | $178,178 | |
| 78 | July 2010 | $178,178 | $549,030 | $542,510 | | $6,521 | $184,699 | |
| 79 | August 2010 | $184,699 | $591,041 | $483,170 | | $107,871 | $292,570 | |
| 80 | Sept 2010 | $292,570 | $547,792 | $432,045 | | $115,747 | $408,317 | |
| 81 | Oct 2010 | $408,317 | $459,399 | $418,744 | | $40,655 | $448,972 | |
| 82 | Nov 2010 | $448,972 | $406,237 | $414,036 | | ($7,799) | $441,173 | |
| 83 | Dec 2010 | $441,173 | $484,970 | $474,974 | | <u>$9,996</u> | $451,169 | |
| 84 | 12/29/10 | | | | | <u>($200,000)</u> | $251,169 | Per RIPUC 12/22/2010 **<u>(2)</u>** |
| 85 | | Period Cumulative Over/(Under) collection | | | | $364,339 | | |
| 86 | | | | | | | | |
| 87 | Forecast Cumulative Over/(Under) Collection at 12/31/2010 | | | | | | $251,169 | |
| 88 | | | | | | | | |
| 89 | | | | | | | | |
| 90 | | | | | | | | |
| 91 | **<u>Combined Standard Offer, Transition Charge, and Transmission Charge</u>** | | | | | | | |
| 92 | | | | | | | | |
| 93 | | | | | | | | |
| 94 | | **<u>Start Bal</u>** | **<u>Revenue</u>** | **<u>Expense</u>** | | **<u>Monthly</u>** | **<u>Cumulative</u>** | |
| 95 | 1/31/2011 | $251,169 | $530,611 | $471,428 | | $59,183 | $310,351 | |
| 96 | 2/28/2011 | $310,351 | $508,399 | $447,989 | | $60,410 | $370,761 | |
| 97 | 3/31/2011 | $370,761 | $431,557 | $462,952 | | ($31,395) | $339,367 | |
| 98 | 4/30/2011 | $339,367 | $445,182 | $428,074 | | $17,108 | $356,474 | |
| 99 | 5/31/2011 | $356,474 | $394,200 | $436,527 | | ($42,327) | $314,147 | |
| 100 | 6/30/2011 | $314,147 | $401,231 | $442,877 | | ($41,646) | $272,502 | |
| 101 | 7/31/2011 | $272,502 | $509,871 | $494,050 | | $15,821 | $288,322 | |
| 102 | 8/31/2011 | $288,322 | $536,634 | $472,940 | | $63,693 | $352,016 | |
| 103 | 9/30/2011 | $352,016 | $557,743 | $419,551 | | $138,193 | $490,209 | |
| 104 | 10/31/2011 | $490,209 | $442,553 | $452,608 | | ($10,055) | $480,153 | |
| 105 | 11/30/2011 | $480,153 | $407,528 | $446,712 | | ($39,184) | $440,970 | |
| 106 | 12/31/2011 | $440,970 | $430,339 | $478,307 | | ($47,968) | $393,002 | |
| 107 | | | | | | | | |
| 108 | | Period Cumulative Over/(Under) collection | | | | $141,833 | | |
| 109 | | | | | | | | |
| 110 | Forecast Cumulative Over/(Under) Collection at 12/31/2011 | | | | | | $393,002 | |
| 111 | | | | | | | | |
| 112 | | | | | | | | |
| 113 | | | | | | | | |
| 114 | | | | | | | | |
| 115 | | | | | | | | |
| 116 | ***<u>Footnotes:</u>*** | | | | | | | |
| 117 | (1) Transfer to PPRF to increase balance to $500,000 | | | | | | | |
| 118 | | | | | | | | |
| 119 | (2) Transfer to PPRF for SPE project or future rate reduction | | | | | | | |

Testimony Exhibit 2 JRA

**Pascoag Utility District**
**Peak Demand Summary**

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|
| Jan | 9262 | 9176 | 9563 | 8419 | 8962 | 10002 |
| Feb | 9412 | 9468 | 9118 | 9358 | 8856 | 9958 |
| March | 8976 | 9283 | 8425 | 8991 | 8453 | 8651 |
| April | 7941 | 7985 | 6969 | 7252 | 7330 | 7910 |
| May | 7756 | 7987 | 6941 | 7167 | 9683 | 8609 |
| June | 9797 | 10291 | **12065** | 7648 | 10991 | 10241 |
| July | 11424 | 9987 | 10376 | 9627 | **12355** | **12765** |
| August | 11944 | 11062 | 9656 | 11075 | 11379 | 10786 |
| Sept | 8463 | 9450 | 9048 | 8319 | 11606 | |
| October | 8120 | 7789 | 8235 | 8510 | 8362 | |
| Nov | 8948 | 8750 | 8976 | 8347 | 8835 | |
| Dec | 9212 | 10285 | 9656 | 9726 | 10015 | |

MMWEC
Public Energy Partners

TO: Nuclear Mix No. 1 Project Participants
Nuclear Project No. 3 Project Participants
Nuclear Project No. 4 Project Participants
Nuclear Project No. 5 Project Participants
Project No. 6 Participants

**Testimony Exhibit 3-JRA**

FROM: Carol Martucci, Director, Accounting and Financial Reporting

DATE: July 20, 2011

SUBJECT: June 30, 2011 Surplus Funds

Attached is a schedule with the projected Surplus Funds as of June 30, 2011 for each of the above noted Projects. These amounts will be finalized by August 20, 2011. Note that the actual results may vary from this projection.

The box below represents the options for receiving the Surplus Funds amount. Please choose one of the options by marking an "x" in the appropriate box.

- ☐ Apply the Surplus Funds amount to each Project **as a credit** against the September billing (invoice(s) dated August 20, 2011) **and send a check** for any amount in excess of the September billing for each Project.
- ☐ Apply the Surplus Funds amount to each Project **as a credit** against the September billing (invoice(s) dated August 20, 2011). If the credit exceeds the amount of the September bill, please **credit the remainder** on the following month's billing for each Project.
- ☑ Apply the Surplus Funds amount **ratably as a credit** over the balance of the Contract Year ending June 30, 2012. Number of months to be credited over: 10 **months** (No more than 10 months)
- ☐ Please send a **check for the entire amount** of the Surplus Funds on August 20, 2011.

Please email Kimberly Potito at kpotito@mmwec.org with your response no later than August 12, 2011.

If you have any questions, you may contact Carol Martucci, (413) 308-1375 or cmartucci@mmwec.org or Seema Patel at (413) 308-1382 or spatel@mmwec.org.

# PASCOAG UTILITY DISTRICT

| PROJECT: | SURPLUS FUNDS Estimated 2011 | 2010 | Variance Est 2011 vs. 2010 |
|---|---|---|---|
| NUCLEAR MIX 1 | $ - | $ - | $ - |
| NUCLEAR PROJECT 3 | - | - | - |
| NUCLEAR PROJECT 4 | - | - | - |
| NUCLEAR PROJECT 5 | - | - | - |
| PROJECT 6 | 77,690.61 | 95,156.97 | (17,466.36) |
| | $ 77,690.61 | $ 95,156.97 | $ (17,466.36) |

8,650.63/mt
FY 2010/2011
(11 month payback)

7,769.06/mt
2011-2012 FY
(10 month payback)

## Judy Allaire

**rom:** Judy Allaire
**Sent:** Wednesday, July 27, 2011 1:24 PM
**To:** 'KPotito@mmwec.org'
**Cc:** Michael Kirkwood
**Subject:** Pascoag's surplus funds
**Attachments:** MMWEC Surplus funds 2011.pdf

Kimberly,

Pascoag will take credit over a ten month period. Was this changed? I seem to remember that it was always an 11 month period in the past.

Thanks
Judy

*Judith R. Allaire*
*Assistant General Manager*
*Pascoag Utility District*
*(401) 568-6222*
*(401) 568-0066 (F)*
*jallaire@pud-ri.org*

## Reconciliation of Forecast to Actual

| Month | Budget (1) | Actual | Difference | Energy (MWH) Budget (1) | Energy (MWH) Actual | Difference (Energy) | Actual Cost MWH | Budget Cost MWH |
|---|---|---|---|---|---|---|---|---|
| Jan 2011 | $475,934 | $471,428 | ($4,506) | 4,938 | 5,105 | 167 | $92.34 | $96.38 |
| Feb 2011 | $441,164 | $447,989 | $6,825 | 4,318 | 4,410 | 92 | $101.59 | $102.17 |
| Mar 2011 | $442,489 | $462,952 | $20,463 | 4,463 | 4,759 | 296 | $97.28 | $99.15 |
| Apr 2011 | $461,180 | $428,074 | ($33,106) | 3,999 | 4,040 | 41 | $105.97 | $115.32 |
| May 2011 | $426,799 | $436,527 | $9,728 | 4,142 | 4,093 | (49) | $106.65 | $103.04 |
| Jun 2011 | $469,553 | $442,877 | ($26,676) | 4,584 | 4,638 | 54 | $95.49 | $102.43 |
| Jul 2011 | $503,077 | $494,050 | ($9,027) | 5,432 | 5,679 | 247 | $87.00 | $92.61 |
| Aug 2011 | $519,358 | $472,940 | ($46,418) | 5,210 | 4,892 | (318) | $96.67 | $99.68 |
| Sep 2011 | $464,149 | $419,551 | ($44,598) | 4,354 | 4,506 | 152 | $93.11 | $106.60 |
| Oct 2011 (Revised) | $ 452,608 | $452,608 | $0 | 4,350 | 4,350 | 0 | $104.05 | $104.05 |
| Nov 2011 (Revised) | $446,712 | $446,712 | $0 | 4,407 | 4,407 | 0 | $101.36 | $101.36 |
| Dec 2011 (Revised) | $478,307 | $478,307 | $0 | 4,988 | 4,988 | 0 | $95.89 | $95.89 |
| Total | $5,581,330 | $5,454,015 | ($127,315) | 55,185 | 55,867 | 682 | $97.63 | $101.14 |
| Original Forecast | $5,593,165 | | | | | | | |
| | ($11,835) | | | | "Average" MWH cost | | $97.63 | $101.14 |

(1) From 12/2010 filing, Schedule F

Testimony Exhibit 5-JRA
Provided by ENE

# 2012 Budget Assumptions

| MWH | | Total Costs | $/MWH |
|---|---|---|---|
| 55,189 | **2011 Original Budget** | $5,593,162 | $ 101.35 |
| 55,449 | **2012 Budget** | $5,175,967 | $ 93.35 |
| 260 | **Total Increase of** | $ (417,195) | $ 8.00 |

**Details of Increase:**

| | | | Adj: | Total Adj of : |
|---|---|---|---|---|
| 1 | Adjustments to NYPA Expenses | | | |
| | Demand Rate | Rate Modification Plan -prelimary staff report 7/11 | $ 26,772 | |
| | Transmission | 8.5% Increase based on last year's actual costs | $ 19,200 | |
| | Energy | Capacity Factor from 85% to 75% | $ 222 | |
| | | Total NYPA Adjustments | | $ 46,194 |
| 2 | Adjustments to Seabrook Costs | | | |
| | Jan-Jun | Fixed Cost from $68.50 to $67.80/kw-mo | $ 8,610 | |
| | Jul-Dec | Fixed Cost from $73.25 to $64.85/kw-mo | | |
| | Jan-Apr | Adjusted the Flush of funds from $8,610/mo to $7,700/mo | $ 3,640 | |
| | Jan-Dec | Capacity Factor from 92% to 98.7% | $ (697) | $ 11,553 |
| | | Total Seabrook Adjustments | | |
| 3 | Adjustments to ENE's Fee from $6,200/mo to $6,386/mo | | | $ 2,232 |
| 4 | Revised Capacity Forecast | | | $ - |
| 5 | Replaced the 3MW ATC purchase from Dominion @ $79.50 and the BELD Peaking Load Follow purchase at $59.00 with the Balancing Purchase from Constellation @ $59.90 | | | $ (753,807) |
| 6 | Entered Est Generation for Miller Hydro Purchase for Calendar 2012 | | | $ 231 |
| 7 | Entered Est Generation for Spruce Mountain Purchase for Jan - Aug 2012 | | | $ 109,854 |
| 8 | Increase in resales to ISO-NE for Off-Peak Power | | | $ 100,517 |
| 9 | Adjustments to Estimated ISO Expenses | | | |
| | | Annual Fee | $ 95 | |
| | | Load Based Charges | $ 347 | |
| | | Scheduled Charges | $ (8,455) | |
| | | Total ISO Expense Adjustments | | $ (8,012) |
| 10 | Adjusted OATT RNS Rate to $5.94/kw-mo for Jan-May forecast Jul-Dec @ $6.68/kw-mo | | | $ 97,472 |
| 11 | Reduced DAF Charges | | | |
| | Jan-Sep | from $8,500/mo to $6,600/mo | $ (17,100) | |
| | Oct-Dec | from $9,510/mo to $7,400/mo | $ (6,330) | |
| | | Total DAF Adjustments | | $ (23,430) |
| | | **Total Adjustment** | | **$ (417,195)** |
| | | Variance | | $ (0) |

**Pascoag Utility District**
**Restricted Fund Account**
**RIPUC Docket No. 3709 Purchase Power**
**Year Ending December 31, 2011**

| Date | Beginning | | Interest | | Deposits | | Withdrawals | | Balance | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| 31-Dec | $ 64,856.63 | | | | | | | | $ 64,856.63 | 0 |
| 31-Jan | | | $ 109.15 | | | | | | $ 64,965.78 | |
| 9-Feb | | | | | $ 235,000.00 | | | | $ 299,965.78 | From Operating Reserve, y/e 2007 |
| 13-Feb | | | $ 106.05 | | | | | | $ 300,071.83 | to hi-yield account |
| 29-Feb | | | $ 429.35 | | | | | | $ 300,501.18 | hi-yield account |
| 31-Mar | | | $ 753.81 | | | | | | $ 301,254.99 | |
| 30-Apr | | | $ 731.30 | | | | | | $ 301,986.29 | |
| 31-May | | | $ 653.64 | | | | | | $ 302,639.93 | |
| 30-Jun | | | $ 661.28 | | | | | | $ 303,301.21 | |
| 31-Jul | | | $ 662.73 | | | | | | $ 303,963.94 | |
| 31-Aug | | | $ 621.28 | | | | | | $ 304,585.22 | |
| 30-Sep | | | $ 687.03 | | | | | | $ 305,272.25 | |
| 30-Nov | | | $ 1,016.55 | | | | | | $ 306,288.80 | |
| 31-Dec | | | $ 547.54 | | | | | | $ 306,836.34 | |
| 30-Jan | | | $ 567.44 | | | | | | $ 307,403.78 | |
| 30-Jan | | | $ 18.95 | | | | | | $ 307,422.73 | |
| 30-Jan | | | $ (18.95) | | | | | | $ 307,403.78 | |
| 28-Feb | | | $ 606.39 | | | | | | $ 308,010.17 | |
| 23-Mar | | | $ 588.59 | | | | | | $ 308,598.76 | |
| 22-Apr | | | $ 570.70 | | | | | | $ 309,169.46 | |
| 9-May | | | $ 571.75 | | | | | | $ 309,741.21 | |
| Jun-09 | | | $ 415.82 | | | | | | $ 310,157.03 | |
| 9-Jul | | | $ 460.99 | | | | | | $ 310,618.02 | |
| 30-Aug | | | $ 382.95 | | | | | | $ 311,000.97 | |
| 9/17/2009 | | | | | | | $ (15,000.00) | | $ 296,000.97 | to ENE for increase ISO expense, ok per Division |
| 30-Sep | | | $ 383.43 | | | | | | $ 296,384.40 | |
| 19-Oct | | | $ 377.59 | | | | | | $ 296,761.99 | |
| 9-Nov | | | $ 304.89 | | | | | | $ 297,066.88 | |
| Dec-09 | | | $ 305.20 | | | | | | $ 297,372.08 | |
| Jan-10 | | | | | $ 200,000.00 | | | | $ 497,372.08 | from over collection, per RIPUC order 12/09 |
| Jan-10 | | | $ 325.89 | | | | | | $ 497,697.97 | |
| Feb-10 | | | $ 511.33 | | | | | | $ 498,209.30 | |
| Mar-10 | | | $ 435.42 | | | | | | $ 498,644.72 | |
| Apr-10 | | | $ 465.86 | | | | | | $ 499,110.58 | |
| Apr-10 | | | $ 165.46 | | | | | | $ 499,276.04 | to close and transfer to 18 mt, higher interest acct |
| May-10 | | | | | | | | | $ 499,276.04 | |
| Jun-10 | | | | | | | | | $ 499,276.04 | |
| Jul-10 | | | | | | | | | $ 499,276.04 | |
| Aug-10 | | | | | | | $ (250,000.00) | | $ 249,276.04 | ok per Division (high power bills, low cash flow) |
| Sep-10 | | | | | $ 100,000.00 | | | | $ 349,276.04 | Partial reimbursement |
| Oct-10 | | | | | $ 100,000.00 | | | | $ 449,276.04 | Partial reimbursement |
| Oct-10 | | | | | $ 50,000.00 | | | | $ 499,276.04 | Final reimbursement |
| Nov-10 | | | | | | | | | $ 499,276.04 | |
| Dec-10 | | | | | $ 200,000.00 | | | | $ 699,276.04 | for "RSF" approved by Comm at 12/22 hearing |
| Apr-11 | | | | | | | $ (100,000.00) | | $ 599,276.04 | ok, per Division (low cash flow, cycle 5 billing issue) |
| 5/4/2011 | | | | | $ 50,000.00 | | | | $ 649,276.04 | Reimbursement #1 |
| 10/24/2011 | | | | | $ 30,000.00 | | | | $ 679,276.04 | Reimbursement #2 |
| | $ 64,856.63 | $ - | $ 14,419.41 | $ - | $ 965,000.00 | $ - | $ (365,000.00) | $ - | $ 679,276.04 | |

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: PASCOAG UTILITY DISTRICT : DOCKET NO. 3546

**COMMISSION DATA REQUESTS DIRECTED TO PASCOAG UTILITY DISTRICT**
**September 21, 2011**

1. What major capital purchase has been deferred in 2011 in order to reduce this year's capital budget? For how long will this capital purchase be deferred.

2. What, if any, planned capital purchases will be deferred in 2012?

3. Identify the capital projects that Pascoag is proposing to complete in 2011 and 2012 and the approximate cost of each project/purchase.

4. When will the Request for Proposals be issued for the cost of service/rate design study?

1. **<u>What major capital purchase has been deferred in 2011 in order to reduce this year's capital budget? For how long will this capital purchase be deferred?</u>**

Response Provided by: Judith R. Allaire

In 2011, Pascoag had an approved capital purchase for a new bucket truck in the amount of $150,000. Based on the responses to Pascoag's Request for Proposals on this truck, as well as the current fiscal considerations, this purchase will be deferred until calendar year 2013.

Because of Pascoag's preventative maintenance schedule, the District's vehicle fleet is in excellent condition. The bucket truck that will be replaced is a 1994 International, but since these types of vehicles have limited mileage, a twenty-year life is not unusual.

There are no major repairs needed to keep this vehicle operational during the remainder of 2011 and 2012.

**2. <u>What, if any, planned capital purchases will be deferred in 2012?</u>**

Response Provided by: Judith R. Allaire

In 2012, Pascoag will defer the purchase of the new bucket truck, improvements to the business office, and the purchase of a pickup truck. In addition, other capital projects had reductions in budgets – these are identified in Commission Data Request 3.

These deferrals or reductions are in no way impeding the District's ability to provide reliable electric service to its customers, while maintaining safe working conditions for its employees.

Commission Data Request
RIPUC Docket No. 3546
Commission Request 3

3. **Identify the capital projects that Pascoag is proposing to complete in 2011 and 2012 and the approximate cost of each project/purchase.**

Response Provided by: Judith R. Allaire

In 2011, Pascoag has completed the following capital projects:

| | |
|---|---|
| Computer/Office Equipment | $ 4,047 |
| Transformers | $41,882 |
| Street Lighting | $ 2,469 |
| Overhead System Improvements | $ 6,382 |
| Communication Equipment | $ 1,705 |
| Chipper | $29,544 |
| **TOTAL** | **$86,029** |

For the remainder of 2011, Pascoag's capital project requirements will be limited to distribution system related expenses, but are not expected to exceed an additional $20,000. To-date, Pascoag has funded the Restricted Fund Account at a level of $185,000.

In 2012, Pascoag has the following capital projects scheduled:

| | |
|---|---|
| Poles | $10,000 |
| Meters/Meter Equipment | $ 6,000 |
| Transformers | $20,000 |
| Street Lighting | $ 7,000 |
| Contingency/Emergency | $ 7,500 |
| Overhead System Improvements | $ 7,000 |
| Office Equipment/Computers | $ 5,000 |
| **TOTAL** | **$62,500** |

4. **When will the Request for Proposals be issued for the cost of service/rate design study?**

Response Provided by: Judith R. Allaire

The Request for Proposals is complete and will be issued in early October. The anticipated schedule is listed below.

***ANTICIPATED SCHEDULE OF EVENTS***

| EVENT | DATE |
|---|---|
| Post Request for Proposal | October 10, 2011 |
| Pre-Bid Meeting | October 24, 2011 |
| Questions Due | October 31, 2011 |
| Addendum Issued (If required) | November 14, 2011 |
| RFP Response Due Date | November 28, 2011 |
| Vendor Presentations/Interviews | December 12, 2011 |
| Anticipated Award Date | December 15, 2011 |
| Purchase Order Issued | December 30, 2012 |
| Draft written reports to PUD for review | May 30, 2012 |
| Submit Electric Rate Case - RIPUC | June 15, 2012 |
| Submit final draft to PUD Board – Water | June 25, 2012 |
| | |
| | |

## DATA REQUESTS TO PASCOAG UTILITY DISTRICT FROM THE RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS DOCKET NO. 3546

## DATA REQUESTS

**Div 1-1.** What is Pascoag's current outstanding long-term debt balance?

**Div 1-2.** If the response to Div 1-1 above is $0, when did Pascoag discharge its most current long-term debt obligation?

**Div 1-3.** At this time, does Pascoag anticipate incurring long-term debt (terms in excess of one year) within the next two years?

Division Data Request
RIPUC Docket No. 3546
Division Request 1-1

**Div 1-1: What is Pascoag's current outstanding long-term debt balance?**

Response Provided by: Judith R. Allaire

At this time the Electric Department has no outstanding long-term debt.

**Div 1-2:** **If the response to Div 1-1 above is $0, when did Pascoag discharge its most current long-term debt obligation?**

Response Provided by: Judith R. Allaire

Pascoag's most current long-term debt obligation was discharged in May 2010.

The debt was satisfied using money from the District's Restricted Fund account. A summary of that transaction is attached with this submittal and labeled as "Division Data Request - Exhibit A".

**Pascoag Utility District**
**Restricted Fund Account**
**RIPUC Docket No 3546**
**Year Ending December 31, 2010**

| | | | | | | |
|---|---|---|---|---|---|---|
| | Annual Deposit Required: | | $ 376,651.00 | | | |
| Date | Beginning Balance | Interest | Deposits | Withdrawals | Balance | Notes |
| 12/31/09 | $ 538,988.90 | | | | $ 538,988.90 | |
| 1/31/10 | | $ 590.67 | | | $ 539,579.57 | |
| 2/19/10 | | $ 554.36 | $ 30,000.00 | | $ 570,133.93 | (Jan contribution) |
| 3/19/10 | | $ 498.28 | $ 25,000.00 | $ (8,637.00) | $ 586,995.21 | capacitors |
| 4/19/10 | | $ 548.40 | $ 30,000.00 | $ (15,163.00) | $ 602,380.61 | poles, cutouts |
| 4/30/10 | | $ 199.69 | | | $ 602,580.30 | account chgd to 18 month, higher interest rate |
| 5/25/10 | | | $ 35,000.00 | | $ 637,580.30 | |
| 5/25/10 | | | | $ (129,800.00) | $ 507,780.30 | new forestry truck |
| 5/25/10 | | | | $ (284,043.92) | $ 223,736.38 | payoff LTD w/BankRI, approved BUC 5/24/2010 |
| 6/21/10 | | | $ 45,000.00 | | $ 268,736.38 | (This account moved to an 18-month term acct) |
| 7/28/10 | | | $ 35,000.00 | | $ 303,736.38 | |
| 7/28/10 | | | | $ (22,290.00) | $ 281,446.38 | (transformers,server,meters) |
| 8/24/10 | | | $ 35,000.00 | | $ 316,446.38 | |
| 9/24/10 | | | $ 35,000.00 | | $ 351,446.38 | |
| 10/20/10 | | | $ 40,000.00 | $ (14,295.00) | $ 377,151.38 | cutouts, transformers, wire |
| 11/19/10 | | | $ 40,000.00 | | $ 417,151.38 | |
| 19-Nov | | | | $ (13,807.00) | $ 403,544.38 | balance of server/installation |
| 22-Dec | | | $ 25,000.00 | | $ 428,544.38 | |
| 122/22 | | | | $ (15,000.00) | $ 413,544.38 | Transformer |
| | $ 538,988.90 | $ 2,391.40 | $ 375,000.00 | $ (502,835.92) | $ 413,544.38 | |

Division Data Request Exhibit A

Division Data Request
RIPUC Docket No. 3546
Division Request 1-3

**Div 1-3:** **At this time, does Pascoag anticipate incurring long-term debt (terms in excess of one year) within the next two years?**

Response Provided by: Judith R. Allaire

Pascoag has no plans to incur any long-term debt in the next two years.

Testimony Exhibit 8-JRA

**Pascoag Utility District**
**Restricted Fund Account**
**RIPUC Docket No 3546**
**Year Ending December 31, 2011**

**Annual Deposit Required:** **$ 376,651.00**

| Date | Beginning Balance | Interest | Deposits | Withdrawals | Balance | Notes |
|---|---|---|---|---|---|---|
| 12/31/10 | $ 413,544.38 | | | | $ 413,544.38 | |
| 2/7/11 | | | $ 30,000.00 | | $ 443,544.38 | |
| 2/7/11 | | | | $ (24,343.00) | $ 419,201.38 | laptop ($2953); transformers ($21,390) |
| 3/16/11 | | | $ 25,000.00 | | $ 444,201.38 | |
| 4/9/11 | | | $ 25,000.00 | | $ 469,201.38 | |
| 5/17/11 | | | $ 40,000.00 | | $ 509,201.38 | |
| 6/6/11 | | | | $ (24,167.00) | $ 485,034.38 | transformers, communicaiton equipment, copier, street lig |
| 6/24/11 | | | $ 25,000.00 | | $ 510,034.38 | |
| 7/26/11 | | | $ 40,000.00 | | $ 550,034.38 | |
| 7/26/11 | | | | $ (7,975.00) | $ 542,059.38 | transformer |
| 8/5/11 | | | | $ (29,544.10) | $ 512,515.28 | chipper |
| | $ 413,544.38 | $ - | $ 185,000.00 | $ (86,029.10) | $ 512,515.28 | |

**Summary of Accounts Payable (1)**

| | 1 - 30 Days | 31 - 60 Days | 61 - 90 Days | Over 90 Days | Balance |
|---|---|---|---|---|---|
| Apr 07 | $ 15,387 | | | | $ 15,387 |
| May 07 | $ - | | | | $ - |
| June 07 | $ 448 | | | | $ 448 |
| July 07 | $ 557 | | | | $ 557 |
| Aug 07 | $ 7,472 | | | | $ 7,472 |
| Sept 07 | $ 138,976 | | | | $ 138,976 |
| Oct 07 | $ - | | | | $ - |
| Nov 07 | $ 22,446 | | | | $ 22,446 |
| Dec 07 | $ 36,743 | | | | $ 36,743 |
| Jan 08 | $ 46,737 | | | | $ 46,737 |
| Feb 08 | $ - | | | | $ - |
| Mar 08 | $ 15,470 | | | | $ 15,470 |
| Apr 08 | $ - | | | | $ - |
| May 08 | $ 5,422 | | | | $ 5,422 |
| Jun 08 | $ - | | | | $ - |
| July 08 | $ 29,002 | | | | $ 29,002 |
| Aug 08 | $ - | | | | $ - |
| Sept 08 | $ 10,043 | | | | $ 10,043 |
| Oct 08 | $ 8,096 | | | | $ 8,096 |
| Nov 08 | $ 6,312 | | | | $ 6,312 |
| Dec 08 | $ - | | | | $ - |
| Jan 09 | $ - | | | | $ - |
| Feb 09 | $ 13,230 | | | | $ 13,230 |
| Mar 09 | $ 13,288 | | | | $ 13,288 |
| Apr 09 | $ 25,323 | | | | $ 25,323 |
| May 09 | $ 21,821 | | | | $ 21,821 |
| 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 |

**(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 | |
|---|---|---|---|---|---|---|
| Apr 2007 | $ 252,966 | $ 54,306 | $ 13,941 | $ 12,386 | $ 333,599 | |
| May 2007 | $ 215,873 | $ 59,502 | $ 9,125 | $ 14,196 | $ 298,696 | |
| June 2007 | $ 233,088 | $ 43,179 | $ 7,645 | $ 16,996 | $ 300,908 | |
| July 2007 | $ 274,608 | $ 45,234 | $ 6,832 | $ 15,575 | $ 342,249 | |
| August 2007 | $ 387,819 | $ 44,181 | $ 5,283 | $ 16,661 | $ 453,944 | |
| Sept 2007 | $ 364,419 | $ 85,945 | $ 6,501 | $ 17,682 | $ 474,547 | |
| Oct 2007 | $ 233,592 | $ 66,359 | $ 9,685 | $ 17,713 | $ 327,349 | |
| Nov 2007 | $ 304,490 | $ 63,574 | $ 20,546 | $ 8,901 | $ 397,511 | write offs $13,744 |
| Dec 07 | $ 339,491 | $ 70,950 | $ 22,837 | $ 17,727 | $ 451,005 | |
| Jan 08 | $ 318,270 | $ 80,258 | $ 21,388 | $ 20,202 | $ 440,118 | |
| Feb 08 | $ 341,985 | $ 84,907 | $ 27,459 | $ 23,148 | $ 477,499 | |
| Mar08 | $ 295,550 | $ 83,338 | $ 27,152 | $ 27,190 | $ 433,230 | |
| Apr 08 | $ 275,153 | $ 61,095 | $ 26,255 | $ 30,751 | $ 393,254 | |
| May 08 | $ 280,732 | $ 62,071 | $ 15,852 | $ 30,475 | $ 389,130 | |
| Jun 08 | $ 266,883 | $ 56,812 | $ 12,231 | $ 32,716 | $ 368,642 | |
| July 08 | $ 322,070 | $ 50,007 | $ 9,603 | $ 33,795 | $ 415,475 | |
| Aug 08 | $ 432,831 | $ 73,631 | $ 8,287 | $ 35,308 | $ 550,057 | |
| Sept 08 | $ 295,916 | $ 94,646 | $ 12,386 | $ 33,558 | $ 436,506 | |
| Oct 08 | $ 257,097 | $ 52,588 | $ 12,985 | $ 34,540 | $ 357,210 | |
| Nov 08 | $ 345,898 | $ 76,058 | $ 23,676 | $ 38,830 | $ 484,462 | |
| Dec 08 | $ 231,153 | $ 77,087 | $ 24,591 | $ 27,746 | $ 360,577 | $21,050 write off, Dec 2008 |
| Jan 09 | $ 426,266 | $ 58,313 | $ 27,118 | $ 32,542 | $ 544,239 | |
| Feb 09 | $ 375,162 | $ 126,308 | $ 30,128 | $ 32,923 | $ 564,521 | |
| Mar 09 | $ 288,633 | $ 96,154 | $ 34,557 | $ 34,036 | $ 453,380 | |
| Apr 09 | $ 308,548 | $ 83,189 | $ 33,839 | $ 43,070 | $ 468,646 | |
| May 09 | $ 280,209 | $ 74,044 | $ 20,750 | $ 45,425 | $ 420,428 | |
| 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 | |

Testimony Exhibit 10-JRA

**Summary of Cash Flow January 2011**

| | | | |
|---|---|---|---|
| Operating Cash balance forward | $ 89,266 | | |
| Projected Purchased Power Expenes: | | | |
| ENE | ($230,788) | | |
| roject 6 (MMWEC & HQ) | ($91,309) | | |
| NYPA | ($21,698) | | |
| ENE/ISO | ($81,698) | | |
| | | ($425,493) | |
| Customer Payments | $ 678,158 | | |
| NSF cks | $ - | | |
| Payroll, benefits | ($141,578) | | |
| Misc. vendor payments | ($54,843) | | |
| Annual Insurance Renewal | ($29,305) | | |
| DSM rebates - 2010 | ($13,510) | | |
| Encumbered for RF | ($30,000) | for transfer in Feb | |
| Encumber for Purch Power | $61,000 | carried forward from December | |
| Encumber for Purch Power | ($107,000) | for power invoices due in Feb | |
| | **$26,695** | | |

| | | | |
|---|---|---|---|
| **Other Financial Information:** | | | |
| Accounts Payable Balance | $ 108,809 | | |
| Accounts Receivable Balance | $ 630,640 | | |
| **Summary of Savings/Investments: (Not Restricted)** | | | |
| Contingency/Emergency | $ 10,000 | | |
| Storm Fund | $ 37,703 | | |
| Working Cash Reserve | $ 61,614 | | |
| Dedicated DSM Fund | | | |
| **Total Savings/Investment (NR)** | $ 109,317 | | |
| **Restricted Account(Debt/Capital)** | **$ 413,544** | | |
| **Restricted Account(Purchase Pwr)** | **$ 699,273** | ($499,273 PP; $200,000 RSF) | |
| **Net All Saving/Investment** | | | |
| | | **$ 1,222,134** | |
| **Misc. Accounts:** | | | |
| Customer Deposit Holding Account | $ 200,660 | | |
| Working Capital - on Deposit w/ ENE | $ 114,125 | | |
| Working Capital - on Deposit w/MMWE | $ 2,232 | | |
| **Saving Goal Jan** | | | |
| Restricted Fund | $ 30,000 | (encumbered in January, but will transfer in February) | |

## Summary of Cash Flow February 2011

| | | | |
|---|---|---|---|
| Operating Cash balance forward | $ 26,695 | | |
| Projected Purchased Power Expenes: | | | |
| ENE | ($222,402) | | |
| roject 6 (MMWEC & HQ) | ($90,422) | | |
| NYPA | ($42,685) | | |
| ENE/ISO | ($84,706) | | |
| | | ($440,215) | |
| Customer Payments | $ 676,673 | | |
| NSF cks | $ (834) | | |
| Payroll, benefits | ($118,170) | | |
| Misc. vendor payments | ($161,954) | | |
| Encumbered for RF | $30,000 | from January, for Feb transfer | |
| RF Trans in Feb | ($30,000) | transferred 2/5 | |
| Trans from RF | $24,343 | for laptop, transformers | |
| Encumbered for RF | ($15,000) | from Feb, for March transfer | |
| Encumber for Purch Power | $107,000 | carried forward from January | |
| Encumber for Purch Power | ($29,000) | for power invoices due in March | |
| | **$69,538** | | |

**Other Financial Information:**

| | |
|---|---|
| Accounts Payable Balance | $ 58,185 |
| Accounts Receivable Balance | $ 670,669 |

**Summary of Savings/Investments: (Not Restricted)**

| | | |
|---|---|---|
| Contingency/Emergency | $ 10,000 | |
| Storm Fund | $ 37,703 | |
| Working Cash Reserve | $ 61,614 | |
| Dedicated DSM Fund | | |
| **Total Savings/Investment (NR)** | $ 109,317 | |
| **Restricted Account(Debt/Capital)** | **$ 419,201** | |
| **Restricted Account(Purchase Pwr)** | **$ 699,273** | ($499,273 PP; $200,000 RSF) |
| **Net All Saving/Investment** | | |
| | | **$ 1,227,791** |

**Misc. Accounts:**

| | |
|---|---|
| Customer Deposit Holding Account | $ 200,660 |
| Working Capital - on Deposit w/ ENE | $ 114,125 |
| Working Capital - on Deposit w/MMWE | $ 2,232 |

**Saving Goal Feb**

| | | |
|---|---|---|
| Restricted Fund | $ 30,000 | deposited 2/5 |
| Restricted Fund | $ 15,000 | encumbered in Feb for March deposit |

## Summary of Cash Flow March 2011

| | | | |
|---|---|---|---|
| Operating Cash balance forward | $ 69,538 | | |
| Projected Purchased Power Expenes: | | | |
| ENE | ($194,967) | | |
| roject 6 (MMWEC & HQ) | ($91,173) | | |
| NYPA | ($52,781) | | |
| ENE/ISO | ($80,410) | | |
| | | ($419,331) | |
| Customer Payments | $ 848,972 | | |
| NSF cks | $ (579) | | |
| Payroll, benefits | ($140,115) | | |
| Misc. vendor payments | ($167,030) | | |
| Encumbered in March - RF | ($10,000) | | |
| Trans from encumber RF | $25,000 | ($10,000 from March; $15,000 carried from February) | |
| Trans to Rest Fund | ($25,000) | transferred 3/16 | |
| Encumbered for RF | ($20,000) | encumbered in March for April transfer | |
| Encumber for Purch Power | $29,000 | carried forward from February | |
| Encumber for Purch Power | ($86,000) | for power invoices due in April | |
| | **$104,455** | | |

**Other Financial Information:**

| | |
|---|---|
| Accounts Payable Balance | $ 53,446 |
| Accounts Receivable Balance | $ 503,285 |

**Summary of Savings/Investments: (Not Restricted)**

| | | | |
|---|---|---|---|
| Contingency/Emergency | $ 10,000 | | |
| Storm Fund | $ 37,703 | | |
| Working Cash Reserve | $ 61,614 | | |
| Dedicated DSM Fund | | | |
| **Total Savings/Investment (NR)** | $ 109,317 | | |
| **Restricted Account(Debt/Capital)** | **$ 444,201** | | |
| **Restricted Account(Purchase Pwr)** | **$ 699,273** | ($499,273 PP; $200,000 RSF) | |
| **Net All Saving/Investment** | | | **$ 1,252,791** |

**Misc. Accounts:**

| | |
|---|---|
| Customer Deposit Holding Account | $ 200,660 |
| Working Capital - on Deposit w/ ENE | $ 114,125 |
| Working Capital - on Deposit w/MMWE | $ 2,232 |

**Saving Goal March**

| | | |
|---|---|---|
| Restricted Fund | $ 25,000 | deposited 3/16 |
| Restricted Fund | $ (20,000) | encumbered in March for April deposit |

**Summary of Cash Flow April 2011**

| | | |
|---|---|---|
| Operating Cash balance forward | $ 104,455 | |
| Projected Purchased Power Expenes: | | |
| ENE | ($209,067) | |
| roject 6 (MMWEC & HQ) | ($59,404) | |
| NYPA | ($42,330) | |
| ENE/ISO | ($83,950) | |
| | | ($394,751) |
| Customer Payments | $ 629,414 | |
| NSF cks | $ - | |
| Payroll, benefits | ($111,502) | |
| Misc. vendor payments | ($119,312) | |
| Encumbered in April - RF | ($10,000) | for transfer in May |
| Trans from PPRF | $100,000 | w/Division approval/low cash flow |
| Trans to Rest Fund | ($25,000) | transferred 4/9 |
| Encumbered for RF | $20,000 | encumbered in March for April transfer |
| Encumber for Purch Power | $86,000 | carried forward from March |
| Encumber for Purch Power | ($178,000) | for power invoices due in May & reimburse PPRF |
| | **$101,304** | |

"Encumbered for Purchase Power":
$ (128,000) For May power bills
$ (50,000) for reimbursement to PPRF

**Other Financial Information:**

| | |
|---|---|
| Accounts Payable Balance | $ 16,400 |
| Accounts Receivable Balance | $ 532,259 |

**Summary of Savings/Investments: (Not Restricted)**

| | | |
|---|---|---|
| Contingency/Emergency | $ 10,000 | |
| Storm Fund | $ 37,703 | |
| Working Cash Reserve | $ 61,614 | |
| Dedicated DSM Fund | | |
| **Total Savings/Investment (NR)** | $ 109,317 | |
| **Restricted Account(Debt/Capital)** | **$ 469,201** | |
| **Restricted Account(Purchase Pwr)** | **$ 599,273** | ($399,273 PP; $200,000 RSF) |
| **Net All Saving/Investment** | | Note: transferred $100,000 w/Division ok - low cash<br>**$ 1,177,791** |

**Misc. Accounts:**

| | |
|---|---|
| Customer Deposit Holding Account | $ 200,660 |
| Working Capital - on Deposit w/ ENE | $ 114,125 |
| Working Capital - on Deposit w/MMWE | $ 2,232 |

**Saving Goal April**

| | | |
|---|---|---|
| Restricted Fund | $ 25,000 | deposited 4/9 |
| Restricted Fund | $ (10,000) | encumbered in April, for deposit in May |

## Summary of Cash Flow May 2011

| | | | |
|---|---|---|---|
| Operating Cash balance forward | $ 101,304 | | |
| Projected Purchased Power Expenes: | | | |
| ENE | ($198,995) | | |
| roject 6 (MMWEC & HQ) | ($90,877) | | |
| NYPA | ($32,529) | | |
| ENE/ISO | ($110,128) | | |
| | | ($432,529) | |
| Customer Payments | $ 615,886 | | |
| NSF cks | $ (272) | | |
| Payroll, benefits | ($111,310) | | |
| Misc. vendor payments | ($115,577) | | |
| Trans to Rest Fund | -50000 | Reimbursement #1 | |
| Trans to Rest Fund | ($40,000) | transferred 4/9 | |
| Encumber for Purch Power | $178,000 | carried from April | |
| Encumber for Purch Power | ($66,000) | for power invoices due in May & reimburse PPRF | |
| | **$79,502** | | |

"Encumbered for Purchase Power":

| | | |
|---|---|---|
| $ | (41,000) | for June power bills |
| $ | (25,000) | for reimbursement to PPRF - in June |

**Other Financial Information:**

| | |
|---|---|
| Accounts Payable Balance | $ 72,992 |
| Accounts Receivable Balance | $ 489,264 |

**Summary of Savings/Investments: (Not Restricted)**

| | | |
|---|---|---|
| Contingency/Emergency | $ 10,000 | |
| Storm Fund | $ 37,703 | |
| Working Cash Reserve | $ 61,614 | |
| Dedicated DSM Fund | | |
| **Total Savings/Investment (NR)** | $ 109,317 | |
| **Restricted Account(Debt/Capital)** | **$ 509,201** | |
| **Restricted Account(Purchase Pwr)** | **$ 649,273** | ($399,273 PP; $200,000 RSF) |
| **Net All Saving/Investment** | | Note: transferred $100,000 w/Division ok - low cash<br>$50,000 reimbursed in May<br>**$ 1,267,791** |

**Misc. Accounts:**

| | |
|---|---|
| Customer Deposit Holding Account | $ 200,660 |
| Working Capital - on Deposit w/ ENE | $ 114,125 |
| Working Capital - on Deposit w/MMWE | $ 2,232 |

**Saving Goal May**

| | | |
|---|---|---|
| Restricted Fund | $ 40,000 | deposited 5/17 |

## Summary of Cash Flow June 2011

| | | | |
|---|---|---|---|
| Operating Cash balance forward | $ 79,502 | | |
| Projected Purchased Power Expenes: | | | |
| ENE | ($209,457) | | |
| roject 6 (MMWEC & HQ) | ($90,451) | | |
| NYPA | ($24,023) | | |
| ENE/ISO | ($84,024) | | |
| | | ($407,955) | |
| Customer Payments | $ 701,740 | | |
| NSF cks | $ (219) | | |
| Payroll, benefits | ($148,148) | | |
| Misc. vendor payments | ($96,755) | | |
| trans from Rest Fund | $24,167 | transformers, street lights, copier, communication equip | |
| Trans to Rest Fund | ($25,000) | trans 6/24 | |
| Encumber for Purch Power | $71,000 | carried from May | |
| Encumber for Purch Power | ($122,000) | for power invoices due in June & potential reimburse P | |
| | **$76,332** | | |
| | | "Encumbered for Purchase Power": | |

**Other Financial Information:**

| | |
|---|---|
| Accounts Payable Balance | $ 45,891 |
| Accounts Receivable Balance | $ 418,335 |

**Summary of Savings/Investments: (Not Restricted)**

| | | |
|---|---|---|
| Contingency/Emergency | $ 10,000 | |
| Storm Fund | $ 37,703 | |
| Working Cash Reserve | $ 61,614 | |
| Dedicated DSM Fund | | |
| **Total Savings/Investment (NR)** | $ 109,317 | |
| **Restricted Account(Debt/Capital)** | **$ 510,034** | |
| **Restricted Account(Purchase Pwr)** | **$ 649,273** | ($399,273 PP; $200,000 RSF) |
| **Net All Saving/Investment** | | Note: transferred $100,000 w/Division ok - low cash<br>$50,000 reimbursed in May<br>**$ 1,268,624** |

**Misc. Accounts:**

| | |
|---|---|
| Customer Deposit Holding Account | $ 200,660 |
| Working Capital - on Deposit w/ ENE | $ 114,125 |
| Working Capital - on Deposit w/MMWE | $ 2,232 |

**Saving Goal June**

| | | |
|---|---|---|
| Restricted Fund | $ 25,000 | deposited 6/24 |

## Summary of Cash Flow July 2011

| | | |
|---|---|---|
| Operating Cash balance forward | $ 76,332 | |
| | | |
| Projected Purchased Power Expenes: | | |
| ENE | ($209,114) | |
| roject 6 (MMWEC & HQ) | ($92,276) | |
| NYPA | ($23,959) | |
| ENE/ISO | ($73,531) | |
| | | ($398,880) |
| Customer Payments | $ 673,038 | |
| NSF cks | $ - | |
| Payroll, benefits | ($125,013) | |
| Misc. vendor payments | ($115,191) | |
| trans from Rest Fund | $7,975 | transformers |
| Trans to Rest Fund | ($40,000) | trans 7/25 |
| Encumber for Purch Power | $122,000 | carried from June |
| Encumber for Purch Power | ($109,000) | for power invoices due in July & potential reimburse PF |
| | **$91,261** | |
| | | "Encumbered for Purchase Power": |

**Other Financial Information:**

| | |
|---|---|
| Accounts Payable Balance | $ 19,194 |
| Accounts Receivable Balance | $ 492,128 |

**Summary of Savings/Investments: (Not Restricted)**

| | | |
|---|---|---|
| Contingency/Emergency | $ 10,000 | |
| Storm Fund | $ 37,703 | |
| Working Cash Reserve | $ 61,614 | |
| Dedicated DSM Fund | | |
| **Total Savings/Investment (NR)** | $ 109,317 | |
| | | |
| **Restricted Account(Debt/Capital)** | **$ 542,059** | |
| **Restricted Account(Purchase Pwr)** | **$ 649,273** | ($449,273 PP; $200,000 RSF) |
| **Net All Saving/Investment** | | Note: transferred $100,000 w/Division ok - low cash |
| | | $50,000 reimbursed in May |
| | | **$ 1,300,649** |

**Misc. Accounts:**

| | |
|---|---|
| Customer Deposit Holding Account | $ 200,660 |
| Working Capital - on Deposit w/ ENE | $ 114,125 |
| Working Capital - on Deposit w/MMWE | $ 2,232 |

**Saving Goal July**

| | | |
|---|---|---|
| Restricted Fund | $ 40,000 | deposited 7/25 |

**Summary of Cash Flow August 2011**

| | | | |
|---|---|---|---|
| Operating Cash balance forward | $ 91,261 | | |
| Projected Purchased Power Expenes: | | | |
| ENE | ($247,714) | | |
| roject 6 (MMWEC & HQ) | ($98,647) | | |
| NYPA | ($29,407) | | |
| ENE/ISO | ($87,812) | | |
| | | ($463,580) | |
| Customer Payments | $ 703,596 | | |
| NSF cks | $ (492) | | |
| Payroll, benefits | ($109,091) | | |
| Misc. vendor payments | ($84,076) | | |
| trans from Rest Fund | $29,544 | for new chipper | |
| Chipper payt | ($29,544) | | |
| Encumber for Purch Power | $109,000 | carried from July | |
| Encumber for Purch Power | ($141,000) | for current power invoices & potential reimburse PPRF | |
| | **$105,618** | | |
| | | "Encumbered for Purchase Power": | |

**Other Financial Information:**

| | |
|---|---|
| Accounts Payable Balance | $ 34,438 |
| Accounts Receivable Balance | $ 584,974 |

**Summary of Savings/Investments: (Not Restricted)**

| | | |
|---|---|---|
| Contingency/Emergency | $ 10,000 | |
| Storm Fund | $ 37,703 | |
| Working Cash Reserve | $ 61,614 | |
| Dedicated DSM Fund | | |
| **Total Savings/Investment (NR)** | $ 109,317 | |
| **Restricted Account(Debt/Capital)** | **$ 512,515** | |
| **Restricted Account(Purchase Pwr)** | **$ 649,273** | ($449,273 PP; $200,000 RSF) |
| **Net All Saving/Investment** | | Note: transferred $100,000 w/Division ok - low cash<br>$50,000 reimbursed in May<br>**$ 1,271,105** |

**Misc. Accounts:**

| | |
|---|---|
| Customer Deposit Holding Account | $ 200,660 |
| Working Capital - on Deposit w/ ENE | $ 114,125 |
| Working Capital - on Deposit w/MMWE | $ 2,232 |

**Saving Goal August**

Restricted Fund did not make deposit in August

## Summary of Cash Flow September 2011

| | | | |
|---|---|---|---|
| Operating Cash balance forward | $ 105,618 | | |
| Projected Purchased Power Expenes: | | | |
| ENE | ($222,894) | | |
| roject 6 (MMWEC & HQ) | ($90,945) | | |
| NYPA | ($35,589) | | |
| ENE/ISO | ($98,372) | | |
| | | ($447,800) | |
| Customer Payments | $ 778,948 | | |
| NSF cks | $ (138) | | |
| Payroll, benefits | ($188,726) | | |
| Misc. vendor payments | ($92,516) | | |
| Trans from Storm Fund | $35,600 | to help defray storm expense - payroll, subcontractors | |
| Encumber for Purch Power | $141,000 | carried from August | |
| Encumber for Purch Power | ($225,000) | for current power invoices & potential reimburse PPRF | |
| | **$106,986** | "Encumbered for Purchase Power": | |

**Other Financial Information:**

| | |
|---|---|
| Accounts Payable Balance | $ 18,850 |
| Accounts Receivable Balance | $ 604,060 |

**Summary of Savings/Investments: (Not Restricted)**

| | | |
|---|---|---|
| Contingency/Emergency | $ 10,000 | |
| Storm Fund | $ 2,103 | (summary of storm expenses attached) |
| Working Cash Reserve | $ 61,614 | |
| Dedicated DSM Fund | | |
| **Total Savings/Investment (NR)** | $ 73,717 | |
| **Restricted Account(Debt/Capital)** | **$ 512,515** | |
| **Restricted Account(Purchase Pwr)** | **$ 649,273** | ($449,273 PP; $200,000 RSF) |
| **Net All Saving/Investment** | | Note: transferred $100,000 w/Division ok - low cash<br>$50,000 reimbursed in May<br>**$ 1,235,505** |

**Misc. Accounts:**

| | |
|---|---|
| Customer Deposit Holding Account | $ 200,660 |
| Working Capital - on Deposit w/ ENE | $ 114,125 |
| Working Capital - on Deposit w/MMWE | $ 2,232 |

**Saving Goal Sept**

Restricted Fund did not make deposit in Sept

## Summary of Tropical Storm Irene Expenses

| | | | |
|---|---|---|---|
| Labor: | | | |
| Overtime - Line crew | $ | 20,327 | (see attached summary sheet) |
| Overtime - office | $ | 1,332 | |
| Contractors | $ | 3,800 | |
| Material/Inventory: | $ | 10,159 | (see attached summary sheet) |
| | $ | 35,618 | |

This summary does not include salaried employees, transportation expense or any markups. It is a summary of additional expenses incurred by the storm and resulting outage.

While we will file for FEMA reimbursement - if it is determined that PUD is eligible - that reimbursement will probably be several months away. In the meantime, it would be my recommendation that we use the money in the District's saving account w/BankRI classified as "Reserved Funds - Storm Fund."

A saving summary is attached for review.

Recommendation: Transfer $35,600 from Storm Fund ***(see Saving Summary - June 2011 tab)***

Approved: ______________________________

Date: ______________________________

PASCOAG UTILITY DISTRICT ELECTRIC DEPT.

DATE 06-Sep-11

DESCRIPTION FINAL BILLING FOR:Hurricane Irene

***Note all cost are based on optimum working conditions. Should working conditions not be optimum cost may rise accordingly.*************

BILL TO FEMA

PUD RATES

| LABOR | OVER TIME HOURS | REGULAR HOURS | TOTAL COST PER MAN |
|---|---|---|---|
| J. BARRENTINE | 31.5 | | $1,661.95 |
| R. LEDUC | 38 | | $2,471.58 |
| R. JENKS | 34.5 | | $2,243.93 |
| W. GUERTIN | 38.5 | | $3,110.07 |
| C. PICCARDI | 32 | | $2,192.00 |
| M. LIMA | 38 | | $2,034.01 |
| J. BLODGETT | 38.5 | | $1,833.06 |
| D. MENARD | 40 | | $1,924.91 |
| M. DUPUIS | 35.5 | | $1,708.36 |
| M. BENOIT | 36.5 | | $1,147.56 |
| G. KIMATION | 36.5 | | $1,147.56 |
| M. WARNER | 36.5 | | $1,482.50 |

| TRANSPORTATION | HOURS | TOTAL | |
|---|---|---|---|
| | | | $20,327.43 |
| TRUCK 12 | 30 | $2,100.00 | |
| TRUCK 11 | 42 | $2,940.00 | |
| TRUCK 7 | 42 | $2,940.00 | |
| TRUCK 5 | 38 | $2,660.00 | |
| TRUCK 4 | 55 | $3,850.00 | |
| TRUCK 14 | | $0.00 | |
| TRUCK 8 | | $0.00 | |
| TRUCK 6 | 55 | $2,200.00 | |
| TRUCK 3 | 35 | $1,400.00 | |
| TRUCK 2 | 55 | $2,200.00 | $20,290.00 |
| TRUCK 1 | 38.5 | $1,540.00 | |
| BACKHOE | 40 | $3,000.00 | |

| MATERIALS | QUANTITY IF POSS. TO LIST | TOTAL | TOTAL W/ TAXES | |
|---|---|---|---|---|
| WIRE | | $3,312.00 | $3,312.00 | |
| HARDWARE | | $3,550.00 | $3,550.00 | INVENTORY |
| POLES | | $1,566.00 | $1,566.00 | |
| ORDERED STOCK | | $1,731.87 | $1,731.87 | |
| MISC. | | $3,800.00 | $3,800.00 | O.S. CONTRACTORS |
| | | | | $13,959.87 |

| ADDITIONAL | COST | |
|---|---|---|
| | | $0.00 |

TOTAL $54,577.30

**Testimony Exhibit 11-JRA**

***ANTICIPATED SCHEDULE OF EVENTS***

| EVENT | DATE |
|---|---|
| Post Request for Proposal | October 10, 2011 |
| Pre-Bid Meeting | October 24, 2011 |
| Questions Due | October 31, 2011 |
| Addendum Issued (If required) | November 14, 2011 |
| RFP Response Due Date | November 28, 2011 |
| Vendor Presentations/Interviews | December 12, 2011 |
| Anticipated Award Date | December 15, 2011 |
| Purchase Order Issued | December 30, 2011 |
| Draft written reports to PUD for review | May 30, 2012 |
| Submit Electric Rate Case - RIPUC | June 15, 2012 |
| Submit final draft to PUD Board – Water | June 25, 2012 |
| | |
| | |

(Pascoag Utility District reserves the right to change schedule of events without prior notice or responsibility to Vendor.)

PASCOAG
UTILITY DISTRICT

Pascoag 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 Status Report**

**RIPUC Docket No. 4298**

Book 2 – Schedule A - H

## Pascoag Utility District - Electric Department

### Summary of Purchase Power Costs (1)

| | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 ESTIMATE | Nov-11 ESTIMATE | Dec-11 ESTIMATE | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Purchased Energy (kWhrs)** | | | | | | | | | | | | | |
| NYPA | 1,600,000 | 1,531,000 | 1,575,000 | 1,379,000 | 1,372,000 | 1,480,000 | 1,702,000 | 1,840,000 | 1,768,000 | 1,400,000 | 1,355,000 | 1,400,000 | 18,402,000 |
| Seabrook | 989,751 | 869,508 | 985,660 | 0 | 232,770 | 921,932 | 990,379 | 988,396 | 956,205 | 491,000 | 939,000 | 970,000 | 9,334,601 |
| ISO Energy Market | | | | 290,800 | | | | | | | | | 290,800 |
| Miller Hydro Group | 146,240 | 109,041 | 192,769 | 189,574 | 201,531 | 125,725 | 70,148 | 71,082 | 136,101 | 104,000 | 137,000 | 138,000 | 1,621,211 |
| Spruce Mnt | | | | | | | | | | | 160,000 | 186,000 | 346,000 |
| ISO Sales | (229,180) | (348,690) | (317,830) | | (33,130) | (310,150) | (193,580) | (683,040) | (675,350) | 0 | (467,000) | (551,000) | (3,808,950) |
| Dominion | 2,232,000 | 2,016,000 | 2,229,000 | 2,160,000 | 2,232,000 | 2,160,000 | 2,232,000 | 2,232,000 | 2,160,000 | 2,232,000 | 2,160,000 | 2,232,000 | 26,277,000 |
| BELD | 366,649 | 232,755 | 94,604 | 20,296 | 87,724 | 260,510 | 877,561 | 444,003 | 160,963 | 123,000 | 123,000 | 613,000 | 3,404,065 |
| **Total** | **5,105,460** | **4,409,614** | **4,759,203** | **4,039,670** | **4,092,895** | **4,638,017** | **5,678,508** | **4,892,441** | **4,505,919** | **4,350,000** | **4,407,000** | **4,988,000** | **55,866,727** |
| **Purchased Power Expense** | | | | | | | | | | | | | |
| NYPA | $ 14,680.00 | $ 14,340.52 | $ 14,557.00 | $ 13,592.68 | $ 13,558.24 | $ 14,089.60 | $ 15,181.84 | $ 15,860.80 | $ 15,506.56 | $ 13,699.00 | $ 13,476.00 | $ 13,699.00 | $172,241 |
| Seabrook | $ 98,499.72 | $ 97,469.15 | $ 98,358.39 | $ 66,474.09 | $ 91,802.27 | $ 97,771.62 | $ 97,705.85 | $ 97,598.05 | $ 97,133.02 | $ 93,745.00 | $ 97,771.00 | $ 98,052.00 | $1,132,380 |
| Excess Funds Credit | $ (8,650.63) | $ (8,650.64) | $ (8,650.34) | $ (8,650.63) | $ (8,650.63) | $ - | $ - | $ (7,769.06) | $ (7,769.06) | $ (7,655.00) | $ (7,655.00) | $ (7,655.00) | ($81,756) |
| MMWEC Admin Chg | $ 28.85 | $ 4.22 | $ 66.36 | $ 13.08 | $ 28.32 | $ 106.38 | $ 120.80 | $ 86.78 | $ - | $ 100.00 | $ 100.00 | $ 100.00 | $755 |
| ISO Energy / Misc. | $ 38,164.85 | $ 35,445.30 | $ 35,509.73 | $ 35,483.07 | $ 35,131.57 | $ 30,735.02 | $ 31,490.80 | $ 34,213.16 | $ 34,198.04 | $ 43,181.00 | $ 43,025.00 | $ 43,449.00 | $440,027 |
| Dominion | $ 177,444.00 | $ 160,272.00 | $177,205.50 | $ 171,720.00 | $ 177,444.00 | $ 171,720.00 | $ 177,444.00 | $ 177,444.00 | $171,720.00 | $ 177,444.00 | $171,720.00 | $ 177,444.00 | $2,089,022 |
| BELD | $ 21,632.29 | $ 13,731.02 | $ 5,581.64 | $ 1,197.46 | $ 5,175.72 | $ 15,370.09 | $ 51,776.10 | $ 26,896.70 | $ 9,496.82 | $ 7,228.00 | $ 7,270.00 | $ 36,166.00 | $201,522 |
| ENE - All Requirements | $ 6,200.00 | $ 6,200.00 | $ 6,758.00 | $ 6,386.00 | $ 6,386.00 | $ 6,386.00 | $ 6,386.00 | $ 6,386.00 | $ 6,386.00 | $ 6,386.00 | $ 6,386.00 | $ 6,386.00 | $76,632 |
| ISO Sales/Purchases | $ (9,358.03) | $ (12,834.08) | $ (8,444.70) | $ 25,203.88 | $ 3,552.53 | $ (6,323.04) | $ (1,183.37) | $ (7,655.11) | $ (18,742.31) | $ - | $ (16,878.00) | $ (26,160.00) | ($78,822) |
| Other Misc Adjust | | | | $ (3,837.07) | | | | | | $ (8,640.00) | $ (8,640.00) | $ (8,640.00) | ($29,757) |
| Miller Hydro Group | $ 9,286.21 | $ 6,924.08 | $ 12,240.81 | $ 12,037.95 | $ 12,797.24 | $ 7,983.54 | $ 4,454.40 | $ 4,513.73 | $ 8,642.39 | $ 6,614.00 | $ 8,687.00 | $ 8,740.00 | $102,921 |
| NYPA FCM | $ (112.56) | | $ (113.33) | $ (114.29) | $ (114.66) | | $ (114.66) | | | | | | ($570) |
| Spruce Mnt | | | | | | | | | | | $ 15,855.00 | $ 18,438.00 | $34,293 |
| UCAP Dominion | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $168,480 |
| Transmission | $ 109,573.55 | $ 121,047.85 | $115,842.77 | $ 94,528.14 | $ 85,376.64 | $ 90,997.38 | $ 96,748.24 | $ 111,325.14 | $ 88,939.12 | $ 106,466.00 | $101,555.00 | $ 104,248.00 | $1,226,648 |
| | | | | | | | | | | | | | $0 |
| | | | | | | | | | | | | | $0 |
| **Total Expense** | **$471,428** | **$447,989** | **$462,952** | **$428,074** | **$436,527** | **$442,877** | **$494,050** | **$472,940** | **$419,551** | **$452,608** | **$446,712** | **$478,307** | **$5,454,015** |

***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, to MMWEC at December 31, 2011. These amounts are from Pascoag's audited financial statements.***

| | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 ESTIMATE | Nov-11 ESTIMATE | Dec-11 ESTIMATE | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2011 aggregate amount | $50,500 | $50,500 | $50,500 | $50,500 | $50,500 | $50,500 | $50,500 | $50,500 | $50,500 | $50,500 | $50,500 | $50,500 | $606,000 |
| Cumulative carry over - 12/2010 | ($2,114) | ($2,114) | ($2,114) | ($2,114) | ($2,114) | ($2,114) | ($2,114) | ($2,114) | ($2,114) | ($2,114) | ($2,114) | ($2,114) | ($25,368) |
| **Monthly Transition Exp.** | **$48,386** | **$48,386** | **$48,386** | **$48,386** | **$48,386** | **$48,386** | **$48,386** | **$48,386** | **$48,386** | **$48,386** | **$48,386** | **$48,386** | **$580,632** |

***(1) Information on Schedule A-1 is from Pascoag's Summary of Purchased Power Invoices, submitted under separate cover as "Book 3"***

A-1

## Pascoag Utility District - Electric Department
## Restated Purchase Power Costs

| | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 ESTIMATE | Nov-11 ESTIMATE | Dec-11 ESTIMATE | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Restated Costs (Dollars) - | | | | | | | | | | | | | |
| Transition: | | | | | | | | | | | - | | $ - |
| Monthly Transition Charge | $50,500 | $50,500 | $50,500 | $50,500 | $50,500 | $50,500 | $50,500 | $50,500 | $50,500 | $50,500 | $50,500 | $50,500 | $606,000 |
| **Restated Transition Cost** | **$50,500** | **$50,500** | **$50,500** | **$50,500** | **$50,500** | **$50,500** | **$50,500** | **$50,500** | **$50,500** | **$50,500** | **$50,500** | **$50,500** | **$606,000** |
| Transmission | $109,574 | $121,048 | $115,843 | $94,528 | $85,377 | $90,997 | $96,748 | $111,325 | $88,939 | $106,466 | $101,555 | $104,248 | $1,226,648 |
| **Net Transmission** | **$109,574** | **$121,048** | **$115,843** | **$94,528** | **$85,377** | **$90,997** | **$96,748** | **$111,325** | **$88,939** | **$106,466** | **$101,555** | **$104,248** | **$1,226,648** |
| Restated Costs (Dollars) Standard Offer | | | | | | | | | | | | | |
| NYPA | $14,680 | $14,341 | $14,557 | $13,593 | $13,558 | $14,090 | $15,182 | $15,861 | $15,507 | $13,699 | $13,476 | $ 13,699.00 | $172,241 |
| MMWEC Admin Chg | $29 | $4 | $66 | $13 | $28 | $106 | $121 | $87 | $0 | $100 | $100 | $ 100.00 | $755 |
| ISO Energy / Misc. | $38,165 | $35,445 | $35,510 | $35,483 | $35,132 | $30,735 | $31,491 | $34,213 | $34,198 | $43,181 | $43,025 | $ 43,449.00 | $440,027 |
| ISO Sales | ($9,358) | ($12,834) | ($8,445) | $25,204 | $3,553 | ($6,323) | ($1,183) | ($7,655) | ($18,742) | $0 | ($16,878) | $ (26,160.00) | ($78,822) |
| Miller Hydro Group | $9,286 | $6,924 | $12,241 | $12,038 | $12,797 | $7,984 | $4,454 | $4,514 | $8,642 | $6,614 | $8,687 | $8,740 | $102,921 |
| ENE | $205,276 | $180,203 | $189,545 | $179,303 | $189,006 | $193,476 | $235,606 | $210,727 | $187,603 | $191,058 | $185,376 | $ 219,996.00 | $2,367,175 |
| Project 6 | $98,500 | $97,469 | $98,358 | $66,474 | $91,802 | $97,772 | $97,706 | $97,598 | $97,133 | $93,745 | $97,771 | $ 98,052.00 | $1,132,380 |
| Excess Fund Credit | ($8,651) | ($8,651) | ($8,650) | ($8,651) | ($8,651) | $0 | $0 | ($7,769) | ($7,769) | ($7,655) | ($7,655) | ($7,655) | ($81,756) |
| UCAP Dominion | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $ 14,040.00 | $14,040 | $168,480 |
| Spruce Mnt | | | | | | | | | | | $ 15,855.00 | $ 18,438.00 | |
| Other | | | $ - | $ (3,837.07) | $0 | | | $ - | $ - | $ (8,640.00) | $ (8,640.00) | $ (8,640.00) | ($29,757) |
| NAYPA FCM | $ (112.56) | $0 | $ (113.33) | $ (114.29) | $ (114.66) | $ - | $ (114.66) | $0 | $0 | | | | ($570) |
| Sub-Total | $361,855 | $326,942 | $347,109 | $333,546 | $351,151 | $351,879 | $397,302 | $361,615 | $330,611 | $346,142 | $345,157 | $374,059 | $4,227,368 |
| Market Value (Transition) | ($50,500) | ($50,500) | ($50,500) | ($50,500) | ($50,500) | ($50,500) | ($50,500) | ($50,500) | ($50,500) | ($50,500) | ($50,500) | ($50,500) | ($606,000) |
| **Restated Cost - SOS** | **$311,355** | **$276,442** | **$296,609** | **$283,046** | **$300,651** | **$301,379** | **$346,802** | **$311,115** | **$280,111** | **$295,642** | **$294,657** | **$323,559** | **$3,621,368** |
| **Restated Power Costs** | **$471,428** | **$447,989** | **$462,952** | **$428,074** | **$436,527** | **$442,877** | **$494,050** | **$472,940** | **$419,551** | **$452,608** | **$446,712** | **$478,307** | **$5,454,015** |

## Pascoag Utility District - Electric Department
## Summary of Revenue and Expenses

| | Jan-11 New Rates Pro-Rated | Feb-11 | Mar-11 | Apr-11 | May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 ESTIMATE | Nov-11 ESTIMATE | Dec-11 ESTIMATE | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Energy Sales to Consumers:** | | | | | | | | | | | | | |
| Kwhrs sold (1) | 4,940,120 | 4,839,888 | 4,115,557 | 4,245,490 | 3,759,300 | 3,826,347 | 4,862,396 | 5,117,620 | 5,318,933 | 4,220,416 | 3,886,403 | 4,103,940 | 53,236,411 |
| Current Cost Recovery(kWhr sales*rate) | | | | | | | | | | | | | - |
| Transition | $56,900 | $54,788 | $46,588 | $48,059 | $42,555 | $43,314 | $55,042 | $57,931 | $60,210 | $47,775 | $43,994 | $46,457 | $603,614 |
| Standard Offer | $371,177 | $342,773 | $290,723 | $299,901 | $265,557 | $270,293 | $343,480 | $361,509 | $375,729 | $298,130 | $274,536 | $289,902 | $3,783,710 |
| Transmission | $102,534 | $110,839 | $94,246 | $97,222 | $86,088 | $87,623 | $111,349 | $117,193 | $121,804 | $96,648 | $88,999 | $93,980 | $1,208,525 |
| **Total** | **$530,611** | **$508,399** | **$431,557** | **$445,182** | **$394,200** | **$401,231** | **$509,871** | **$536,634** | **$557,743** | **$442,553** | **$407,528** | **$430,339** | **$5,595,849** |
| **Over/(Under) Recovery Reconciliation** | | | | | | | | | | | | | |
| | **$59,183** | **$60,410** | **($31,395)** | **$17,108** | **($42,327)** | **($41,646)** | **$15,821** | **$63,693** | **$138,193** | **($10,055)** | **($39,184)** | **($47,968)** | **$141,833** |
| **Purchased Energy: (kWhrs)** | | | | | | | | | | | | | Total |
| NYPA | 1,600,000 | 1,531,000 | 1,575,000 | 1,379,000 | 1,372,000 | 1,480,000 | 1,702,000 | 1,840,000 | 1,768,000 | 1,400,000 | 1,355,000 | 1,400,000 | 18,402,000 |
| Seabrook | 989,751 | 869,508 | 985,660 | 0 | 232,770 | 921,932 | 990,379 | 988,396 | 956,205 | 491,000 | 939,000 | 970,000 | 9,334,601 |
| ISO Energy Market | 0 | 0 | 0 | 290,800 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 290,800 |
| Spruce Mnt | | | | | | | | | | | 160,000 | 186,000 | 346,000 |
| ISO Sales/Purchases | (229,180) | (348,690) | (317,830) | 0 | (33,130) | (310,150) | (193,580) | (683,040) | (675,350) | 0 | (467,000) | (551,000) | (3,808,950) |
| ENE - BELD | 366,649 | 232,755 | 94,604 | 20,296 | 87,724 | 260,510 | 877,561 | 444,003 | 160,963 | 123,000 | 123,000 | 613,000 | 3,404,065 |
| Miller Hydro Group | 146,240 | 109,041 | 192,769 | 189,574 | 201,531 | 125,725 | 70,148 | 71,082 | 136,101 | 104,000 | 137,000 | 138,000 | 1,621,211 |
| Dominion | 2,232,000 | 2,016,000 | 2,229,000 | 2,160,000 | 2,232,000 | 2,160,000 | 2,232,000 | 2,232,000 | 2,160,000 | 2,232,000 | 2,160,000 | 2,232,000 | 26,277,000 |
| **Total** | **5,105,460** | **4,409,614** | **4,759,203** | **4,039,670** | **4,092,895** | **4,638,017** | **5,678,508** | **4,892,441** | **4,505,919** | **4,350,000** | **4,407,000** | **4,988,000** | **55,866,727** |
| **Energy Sales to Consumers: (kWhrs)** | | | | | | | | | | | | | |
| Sales | 4,940,120 | 4,839,888 | 4,115,557 | 4,245,490 | 3,759,300 | 3,826,347 | 4,862,396 | 5,117,620 | 5,318,933 | 4,220,416 | 3,886,403 | 4,103,940 | 53,236,411 |
| street lights | 53,181 | 44,679 | 43,927 | 37,450 | 34,310 | 31,036 | 32,666 | 36,560 | 41,043 | 42,000 | 43,000 | 45,000 | 484,852 |
| **Total** | **4,993,301** | **4,884,567** | **4,159,484** | **4,282,940** | **3,793,610** | **3,857,383** | **4,895,062** | **5,154,180** | **5,359,976** | **4,262,416** | **3,929,403** | **4,148,940** | **53,721,263** |
| System Kwhr losses | 112,159 | (474,953) | 599,719 | (243,270) | 299,285 | 780,634 | 783,446 | (261,739) | (854,057) | 87,584 | 477,597 | 839,060 | 2,145,464 |
| Percent Line Losses | 2.20% | -10.77% | 12.60% | -6.02% | 7.31% | 16.83% | 13.80% | -5.35% | -18.95% | 2.01% | 10.84% | 16.82% | 3.84% |

(1) *See Schedule B for Sales to Customers*

Schedule B-1

For Billing Month: January 2011

| Code | Kw | Kwhrs | Demand/ Distribution | Renewable | Transmission | Transition | Conservation | Cust Chg | Stand Offer | Street Lt** | Sales Tax | Power Ftr | Other | Total | # Cust |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Res | | 3,071,942 | $ 106,413.47 | $ 921.58 | $ 61,684.60 | $ 35,573.09 | $ 6,143.88 | $ 15,884 | $ 235,157.16 | | | | $ 625.00 | $ 462,402.88 | 3971 |
| Comm | | 294,846 | $ 12,141.76 | $ 88.45 | $ 5,920.51 | $ 3,414.32 | $ 589.69 | $ 5,050 | $ 22,570.46 | | $ 7,250.41 | | | $ 57,025.60 | 505 |
| Indus | 5,848.53 | 1,573,332 | $ 38,190.90 | $ 472.00 | $ 31,592.51 | $ 18,219.18 | $ 3,146.66 | $ 4,950 | $ 120,438.56 | | | $ 319.00 | -749.35 | $ 216,579.47 | 66 |
| New Rate | - | | | | $ 3,336.79 | $ (306.83) | | | $ (6,989.52) | | | | | $ (3,959.56) | 4542 |
| SL | | 53,181 | | | | | | | | | | | | $ - | |
| Total | 5,848.53 | 4,993,301 | $ 156,746.13 | $ 1,482.04 | $ 102,534.40 | $ 56,899.76 | $ 9,880.24 | $ 25,884.10 | $ 371,176.67 | $ 6,350.61 | $ 7,250.41 | $ 319.00 | $ (124.35) | $ 738,399.00 | |
| | | (53,181) | | | | | | | | | | | | | |
| sales | w/o st lights | 4,940,120 | | | | | | | | | | | | | |

| | |
|---|---|
| Transmission | $ 102,534.40 |
| Transition | $ 56,899.76 |
| Stand Offer | $ 371,176.67 |
| Revenue | $ 530,610.83 |

For billing month: Feb-11

| Code | Kw | Kwhrs | Demand/ Distribution | Renewable | Transmission | Transition | Conservation | Cust Chg | Stand Offer | Street Lt** | Sales Tax | Power Ftr | Other | Total | # Cust |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Res | | 2,690,841 | $ 93,212.90 | $ 807.25 | $ 61,620.26 | $ 30,460.32 | $ 5,381.68 | $ 15,988 | $ 190,081.01 | | | | $ 110.00 | $ 397,661.18 | 3997 |
| Comm | | 293,572 | $ 12,079.93 | $ 88.07 | $ 6,731.35 | $ 3,323.24 | $ 587.14 | $ 5,050 | $ 20,737.93 | | $ 7,230.11 | | | $ 55,827.77 | 505 |
| Indus | 5,959.53 | 1,855,475 | $ 38,915.73 | $ 548.09 | $ 42,490.38 | $ 21,003.98 | $ 2,841.44 | $ 5,100 | $ 131,940.26 | | | $ 310.94 | -546.55 | $ 242,604.27 | 68 |
| New Rate | - | | | | $ (2.80) | $ 0.15 | | | $ 13.29 | | | | | $ 10.64 | 4570 |
| SL | | 44,679 | | | | | | | | | | | | $ - | |
| Total | 5,959.53 | 4,884,567 | $ 144,208.54 | $ 1,443.42 | $ 110,839.19 | $ 54,787.68 | $ 8,810.27 | $ 26,137.76 | $ 342,772.49 | $ 6,244.58 | $ 7,230.11 | $ 310.94 | $ (436.55) | $ 702,348.42 | |
| | | (44,679) | | | | | | | | | | | | | |
| sales | w/o st lights | 4,839,888 | | | | | | | | | | | | | |

| | |
|---|---|
| Transmission | $ 110,839.19 |
| Transition | $ 54,787.68 |
| Stand Offer | $ 342,772.49 |
| | |
| Revenue | $ 508,399.36 |

TRANSITION = .01132
TRANSMISSION = .02290
SOS = .07064

.10486

Schedule B-2

Schedule B-3

For Billing Month: March 2011

| Code | Kw | Kwhrs | Demand/ Distribution | Renewable | Transmission | Transition | Conservation | Cust Chg | Stand Offer | Street Lt** | Sales Tax | Power Ftr | Other | Total | # Cust |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Res | | 2,283,056 | $ 79,086.06 | $ 684.92 | $ 52,281.98 | $ 25,844.19 | $ 4,566.11 | $ 15,931 | $ 161,275.08 | | | | $ 25.00 | $ 339,693.85 | 3983 |
| Comm | | 283,116 | $ 11,658.72 | $ 84.93 | $ 6,483.36 | $ 3,204.87 | $ 566.23 | $ 5,000 | $ 19,999.31 | | $ 6,998.90 | | | $ 53,996.23 | 500 |
| Indus | 6,432.53 | 1,549,385 | $ 39,183.46 | $ 464.82 | $ 35,480.92 | $ 17,539.04 | $ 3,098.77 | $ 5,175 | $ 109,448.56 | | | $ 333.28 | | $ 210,723.84 | 69 |
| New Rate | - | | | | | | | | | | | | | $ - | 4552 |
| SL | | 43,927 | | | | | | | | | | | | $ - | |
| Total | 6,432.53 | 4,159,484 | $ 129,928.24 | $ 1,234.67 | $ 94,246.26 | $ 46,588.11 | $ 8,231.11 | $ 26,105.41 | $ 290,722.95 | $ 6,087.54 | $ 6,998.90 | $ 333.28 | $ 25.00 | $ 610,501.46 | |
| | | (43,927) | | | | | | | | | | | | | |
| sales | w/o st lights | 4,115,557 | | | | | | | | | | | | | |

| | |
|---|---|
| Transmission | $ 94,246.26 ✓ |
| Transition | $ 46,588.11 ✓ |
| Stand Offer | $ 290,722.95 ✓ |
| | |
| Revenue | $ 431,557.31 |

For Billing Month: April

| Code | Kw | Kwhrs | Demand/ Distribution | Renewable | Transmission | Transition | Conservation | Cust Chg | Stand Offer | Street Lt** | Sales Tax | Power Ftr | Other | Total | # Cust |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Res | | 2,470,176 | $ 85,567.51 | $ 741.05 | $ 56,567.03 | $ 27,962.39 | $ 4,940.35 | $ 15,916 | $ 174,493.23 | | | | $ (521.25) | $ 365,665.92 | 3979 |
| Comm | | 242,033 | $ 9,966.76 | $ 72.61 | $ 5,542.56 | $ 2,739.81 | $ 484.07 | $ 4,818.30 | $ 17,097.21 | | $ 6,470.64 | | | $ 47,191.96 | 482 |
| Indus | 5,934.38 | 1,533,281 | $ 38,751.50 | $ 459.98 | $ 35,112.13 | $ 17,356.74 | $ 3,066.56 | $ 4,575 | $ 108,310.97 | | | | 309.76 | $ 207,942.65 | 61 |
| New Rate | - | | | | | | | | | | | | | $ - | 4522 |
| SL | | 37,450 | | | | | | | | | | | | $ - | |
| Total | 5,934.38 | 4,282,940 | $ 134,285.77 | $ 1,273.65 | $ 97,221.72 | $ 48,058.95 | $ 8,490.98 | $ 25,308.90 | $ 299,901.41 | $ 6,230.26 | $ 6,470.64 | $ - | $ (211.49) | $ 627,030.79 | |
| | | (37,450) | | | | | | | | | | | | | |
| sales | w/o st lights | 4,245,490 | | | | | | | | | | | | | |

| | |
|---|---|
| Transmission | $ 97,221.72 |
| Transition | $ 48,058.95 |
| Stand Offer | $ 299,901.41 |
| | |
| Revenue | $ 445,182.08 |

Schedule B-4

For Billing Month: May 2011

| Code | Kw | Kwhrs | Demand/ Distribution | Renewable | Transmission | Transition | Conservation | Cust Chg | Stand Offer | Street Lt** | Sales Tax | Power Ftr | Other | Total | # Cust |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Res | | 2,003,131 | $ 69,389.74 | $ 600.94 | $ 45,871.70 | $ 22,675.44 | $ 4,006.26 | $ 15,913 | $ 141,501.17 | | | | $ 206.67 | $ 300,164.48 | 3978 |
| Comm | | 235,669 | $ 9,705.08 | $ 70.70 | $ 5,396.82 | $ 2,667.77 | $ 471.34 | $ 4,840 | $ 16,647.66 | | $ 6,514.24 | | | $ 46,313.11 | 484 |
| Indus | 6,012.39 | 1,520,500 | $ 39,260.91 | $ 456.15 | $ 34,819.45 | $ 17,212.06 | $ 3,041.00 | $ 4,725 | $ 107,408.12 | | | $ 332.25 | -734.55 | $ 206,520.39 | 63 |
| New Rate | - | | | | | | | | | | | | | $ - | 4525 |
| SL | | 34,310 | | | | | | | | | | | | $ - | |
| Total | 6,012.39 | 3,793,610 | $ 118,355.72 | $ 1,127.79 | $ 86,087.97 | $ 42,555.28 | $ 7,518.60 | $ 25,476.95 | $ 265,556.95 | $ 6,285.93 | $ 6,514.24 | $ 332.25 | $ (527.88) | $ 559,283.80 | |
| | | (34,310) | | | | | | | | | | | | | |
| sales | w/o st lights | 3,759,300 | | | | | | | | | | | | | |

| | |
|---|---|
| Transmission | $ 86,087.97 |
| Transition | $ 42,555.28 |
| Stand Offer | $ 265,556.95 |
| | |
| Revenue | $ 394,200.20 |

Schedule B-5

Billing Month: June 2011

| Code | Kw | Kwhrs | Demand/ Distribution | Renewable | Transmission | Transition | Conservation | Cust Chg | Stand Offer | Street Lt** | Sales Tax | Power Ftr | Other | Total | # Cust |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Res | | 2,125,783 | $ 73,639.71 | $ 637.73 | $ 48,680.43 | $ 24,063.86 | $ 4,251.57 | $ 16,036 | $ 150,165.31 | | | | $ 86.66 | $ 317,561.24 | 4009 |
| Comm | | 233,499 | $ 9,615.50 | $ 70.05 | $ 5,347.13 | $ 2,643.21 | $ 467.00 | $ 4,900 | $ 16,494.37 | | $ 6,725.76 | | | $ 46,262.91 | 490 |
| Indus | 6,005.39 | 1,467,065 | $ 39,215.19 | $ 440.12 | $ 33,595.79 | $ 16,607.18 | $ 2,934.13 | $ 5,025 | $ 103,633.47 | | | $ 292.93 | -543.86 | $ 201,199.94 | 67 |
| New Rate | - | | | | | | | | | | | | | $ - | 4566 |
| SL | | 31,036 | | | | | | | | | | | | $ - | |
| Total | 6,005.39 | 3,857,383 | $ 122,470.40 | $ 1,147.90 | $ 87,623.35 | $ 43,314.25 | $ 7,652.69 | $ 25,960.86 | $ 270,293.15 | $ 6,246.68 | $ 6,725.76 | $ 292.93 | $ (457.20) | $ 571,270.77 | |
| | | (31,036) | | | | | | | | | | | | | |
| sales | w/o st lights | 3,826,347 | | | | | | | | | | | | | |

| | |
|---|---|
| Transmission | $ 87,623.35 |
| Transition | $ 43,314.25 |
| Stand Offer | $ 270,293.15 |
| | |
| Revenue | $ 401,230.75 |

Schedule B-6

Schedule B-7

For billing month: July 2011

| Code | Kw | Kwhrs | Demand/ Distribution | Renewable | Transmission | Transition | Conservation | Cust Chg | Stand Offer | Street Lt** | Sales Tax | Power Ftr | Other | Total | # Cust |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Res | | 2,786,055 | $ 96,511.29 | $ 835.82 | $ 63,800.66 | $ 31,538.14 | $ 5,572.11 | $ 16,016 | $ 196,806.93 | | | | | $ 411,080.94 | 4004 |
| Comm | | 283,441 | $ 11,672.08 | $ 85.03 | $ 6,490.80 | $ 3,208.55 | $ 566.88 | $ 4,920 | $ 20,022.27 | | $ 8,001.25 | | | $ 54,966.87 | 492 |
| Indus | 6,004.74 | 1,792,900 | $ 39,210.95 | $ 537.87 | $ 41,057.41 | $ 20,295.63 | $ 3,585.80 | $ 5,100 | $ 126,650.46 | | | $ 310.98 | $ (516.73) | $ 236,232.37 | 68 |
| New Rate | - | | | | | | | | | | | | | $ - | 4564 |
| SL | | 32,666 | | | | | | | | | | | | $ - | |
| Total | 6,004.74 | 4,895,062 | $ 147,394.32 | $ 1,458.72 | $ 111,348.87 | $ 55,042.32 | $ 9,724.79 | $ 26,036 | $ 343,479.65 | $ 6,224.03 | $ 8,001.25 | $ 310.98 | $ (516.73) | $ 708,504.20 | |
| | | (32,666) | | | | | | | | | | | | | |
| sales | w/o st lights | 4,862,396 | | | | | | | | | | | | | |

| | |
|---|---|
| Transmission | $ 111,348.87 |
| Transition | $ 55,042.32 |
| Stand Offer | $ 343,479.65 |
| Revenue | $ 509,870.84 |

For Billing Month: August 2011

| Code | Kw | Kwhrs | Demand/ Distribution | Renewable | Transmission | Transition | Conservation | Cust Chg | Stand Offer | Street Lt** | Sales Tax | Power Ftr | Other | Total | # Cust |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Res | | 3,106,190 | $ 107,600.55 | $ 931.86 | $ 71,131.75 | $ 35,162.07 | $ 6,212.38 | $ 16,008 | $ 219,338.46 | | | | $ 350.00 | $ 456,735.06 | 4002 |
| Comm | | 313,942 | $ 12,928.13 | $ 94.18 | $ 7,189.27 | $ 3,553.82 | $ 627.88 | $ 4,910 | $ 22,176.86 | | $ 8,192.94 | | | $ 59,673.10 | 491 |
| Indus | 6,037.26 | 1,697,488 | $ 39,423.31 | $ 509.25 | $ 38,872.48 | $ 19,215.56 | $ 3,394.98 | $ 4,725 | $ 119,910.55 | | | $ 375.03 | -525.9 | $ 225,900.25 | 63 |
| New Rate | - | | | | $ (0.03) | $ - | | | $ 82.24 | | 0.34 | | | $ 82.55 | 4556 |
| SL | | 36,560 | | | | | | | | | | | | $ - | |
| Total | 6,037.26 | 5,154,180 | $ 159,951.99 | $ 1,535.29 | $ 117,193.47 | $ 57,931.46 | $ 10,235.24 | $ 25,643 | $ 361,508.12 | $ 6,194.72 | $ 8,193.28 | $ 375.03 | $ (175.90) | $ 748,585.68 | |
| | | (36,560) | | | | | | | | | | | | | |
| sales | w/o st lights | 5,117,620 | | | | | | | | | | | | | |

| | |
|---|---|
| Transmission | $ 117,193.47 |
| Transition | $ 57,931.46 |
| Stand Offer | $ 361,508.12 |
| Revenue | $ 536,633.04 |

Schedule B-8

Schedule B-9

For billing month: September 2011

| Code | Kw | Kwhrs | Demand/ Distribution | Renewable | Transmission | Transition | Conservation | cutomer chrg | Stand Offer | Street Lt** | Sales Tax | Power Ftr | Other | Total | # Cust |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Res | | 2,944,225 | $ 101,990.19 | $ 883.27 | $ 67,422.75 | $ 33,328.63 | $ 5,888.45 | $ 16,076 | $ 207,980.05 | | | | $ 450.00 | $ 434,019.35 | 4019 |
| Comm | | 344,597 | $ 14,190.50 | $ 103.38 | $ 7,891.27 | $ 3,900.84 | $ 689.19 | $ 4,910 | $ 24,342.33 | | $ 8,803.21 | | $ 500.00 | $ 65,330.73 | 491 |
| Indus | 5,934.62 | 2,030,111 | $ 38,753.07 | $ 609.03 | $ 46,489.54 | $ 22,980.86 | $ 4,060.22 | $ 4,650 | $ 143,407.04 | | | $ 375.75 | 493.72 | $ 261,819.23 | 62 |
| New Rate | - | | | | | | | | | | | | | $ - | 4572 |
| SL | | 41,043 | | | | | | | | | | | | $ - | |
| Total | 5,934.62 | 5,359,976 | $ 154,933.77 | $ 1,595.68 | $ 121,803.57 | $ 60,210.32 | $ 10,637.87 | $ 25,636 | $ 375,729.43 | $ 6,188.07 | $ 8,803.21 | $ 375.75 | $ 1,443.72 | $ 767,357.38 | |
| | | (41,043) | | | | | | | | | | | | | |
| sales | w/o st lights | 5,318,933 | | | | | | | | | | | | | |

| | |
|---|---|
| Transmission | $ 121,803.57 |
| Transition | $ 60,210.32 |
| Stand Offer | $ 375,729.43 |
| | |
| Revenue | $ 557,743.31 |

| A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|
| | | | | | | | Schedule C-1 |

## Combined Standard Offer, Transition Charge, and Transmission Charge

| A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|
| Forecast Cumulative Over/(Under) Collection at 12/31/2009 | | | | | | $286,833 | |
| Jan 2010 | Transfer to PPRF account | | | | $ (200,000) | $86,833 | Per RIPUC 12/23/09 **(1)** |
| | | **Revenue** | **Expense** | | **Monthly** | **Cumulative** | |
| Jan 2010 | $86,833 | $560,925 | $448,121 | | $112,803 | $199,633 | |
| Feb 2010 | $199,633 | $446,702 | $433,141 | | $13,561 | $213,194 | |
| March 2010 | $213,194 | $412,474 | $447,079 | | ($34,605) | $178,589 | |
| April 2010 | $178,589 | $478,725 | $420,739 | | $57,986 | $236,575 | |
| May 2010 | $236,575 | $373,665 | $411,079 | | ($37,414) | $199,161 | |
| June 2010 | $199,161 | $440,377 | $461,359 | | ($20,983) | $178,178 | |
| July 2010 | $178,178 | $549,030 | $542,510 | | $6,521 | $184,699 | |
| August 2010 | $184,699 | $591,041 | $483,170 | | $107,871 | $292,570 | |
| Sept 2010 | $292,570 | $547,792 | $432,045 | | $115,747 | $408,317 | |
| Oct 2010 | $408,317 | $459,399 | $418,744 | | $40,655 | $448,972 | |
| Nov 2010 | $448,972 | $406,237 | $414,036 | | ($7,799) | $441,173 | |
| Dec 2010 | $441,173 | $484,970 | $474,974 | | $9,996 | $451,169 | |
| 12/29/10 | | | | | ($200,000) | $251,169 | Per RIPUC 12/22/2010 **(2)** |
| | Period Cumulative Over/(Under) collection | | | | $364,339 | | |
| Forecast Cumulative Over/(Under) Collection at 12/31/2010 | | | | | | $251,169 | |

## Combined Standard Offer, Transition Charge, and Transmission Charge

| A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|
| | **Start Bal** | **Revenue** | **Expense** | | **Monthly** | **Cumulative** | |
| 1/31/2011 | $251,169 | $530,611 | $471,428 | | $59,183 | $310,351 | |
| 2/28/2011 | $310,351 | $508,399 | $447,989 | | $60,410 | $370,761 | |
| 3/31/2011 | $370,761 | $431,557 | $462,952 | | ($31,395) | $339,367 | |
| 4/30/2011 | $339,367 | $445,182 | $428,074 | | $17,108 | $356,474 | |
| 5/31/2011 | $356,474 | $394,200 | $436,527 | | ($42,327) | $314,147 | |
| 6/30/2011 | $314,147 | $401,231 | $442,877 | | ($41,646) | $272,502 | |
| 7/31/2011 | $272,502 | $509,871 | $494,050 | | $15,821 | $288,322 | |
| 8/31/2011 | $288,322 | $536,634 | $472,940 | | $63,693 | $352,016 | |
| 9/30/2011 | $352,016 | $557,743 | $419,551 | | $138,193 | $490,209 | |
| 10/31/2011 | $490,209 | $442,553 | $452,608 | | ($10,055) | $480,153 | |
| 11/30/2011 | $480,153 | $407,528 | $446,712 | | ($39,184) | $440,970 | |
| 12/31/2011 | $440,970 | $430,339 | $478,307 | | ($47,968) | $393,002 | |
| | Period Cumulative Over/(Under) collection | | | | $141,833 | | |
| Forecast Cumulative Over/(Under) Collection at 12/31/2011 | | | | | | $393,002 | |

***Footnotes:***

(1) Transfer to PPRF to increase balance to $500,000

(2) Transfer to PPRF for SPE project or future rate reduction

| | A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|---|
| 62 | | | | | | | | Schedule C-2 | |
| 63 | | | | | | | | | |
| 64 | | | | **Standard Offer** | | | | | |
| 65 | | | | | | | | | |
| 66 | | | **Revenue** | **Expense** | | **Monthly** | **Cumulative** | | |
| 67 | Jan 2010 | $ (69,001) | $336,845 | 310,688 | | $26,158 | ($42,843) | | |
| 68 | Feb 2010 | $ (42,843) | $315,945 | 269,557 | | $46,388 | $3,544 | | |
| 69 | Mar-10 | $ 3,544 | $291,793 | $293,675 | | ($1,883) | $1,662 | | |
| 70 | April 2010 | $ 1,662 | $338,660 | $265,646 | | $73,014 | $74,676 | | |
| 71 | May 2010 | $ 74,676 | $264,338 | $286,406 | | ($22,068) | $52,608 | | |
| 72 | June 2010 | $ 52,608 | $311,532 | $320,073 | | ($8,541) | $44,067 | | |
| 73 | July 2010 | $ 44,067 | $388,395 | $400,577 | | ($12,182) | $31,885 | | |
| 74 | Aug 2010 | $ 31,885 | $418,114 | $329,997 | | $88,117 | $120,002 | | |
| 75 | Sept 2010 | $ 120,002 | $387,520 | $288,424 | | $99,096 | $219,098 | | |
| 76 | Oct 2010 | $ 219,098 | $324,988 | $276,638 | | $48,350 | $267,448 | | |
| 77 | Nov 2010 | $ 267,448 | $287,381 | $285,163 | | $2,217 | $269,665 | | |
| 78 | Dec 2010 | $ 269,665 | $343,078 | $323,650 | | $19,428 | $289,093 | | |
| 79 | | | | 12/29/2010 | | | ($200,000) | "RSF" to PPRF | |
| 80 | | Period Cumulative Over/(Under) collection | | | | $358,094 | $89,093 | Comm Report & Order | |
| 81 | | | | | | | | 12/22/2010 **(1)** | |
| 82 | Forecast Cumulative Over/(Under) Collection at 12/31/2010 | | | | | | $89,093 | | |
| 83 | | | | | | | | | |
| 84 | | | | | | | | | |
| 85 | | | | | | | | | |
| 86 | | | | | | | | | |
| 87 | | | | | | | | | |
| 88 | | | | | | | | | |
| 89 | | | | | | | | | |
| 90 | | | | | | | | | |
| 91 | | | | **Standard Offer** | | | | | |
| 92 | | | | | | | | | |
| 93 | | **Start Bal** | **Revenue** | **Expense** | | **Monthly** | **Cumulative** | | |
| 94 | 1/31/2011 | $89,093 | $371,177 | $311,355 | | $59,822 | $148,915 | | |
| 95 | 2/28/2011 | $148,915 | $342,773 | $276,442 | | $66,331 | $215,246 | | |
| 96 | 3/31/2011 | $215,246 | $290,723 | $296,609 | | ($5,886) | $209,360 | | |
| 97 | 4/30/2011 | $209,360 | $299,901 | $283,046 | | $16,855 | $226,215 | | |
| 98 | 5/31/2011 | $226,215 | $265,557 | $300,651 | | ($35,094) | $191,121 | | |
| 99 | 6/30/2011 | $191,121 | $270,293 | $301,379 | | ($31,086) | $160,035 | | |
| 100 | 7/31/2011 | $160,035 | $343,480 | $346,802 | | ($3,322) | $156,713 | | |
| 101 | 8/31/2011 | $156,713 | $361,509 | $311,115 | | $50,394 | $207,107 | | |
| 102 | 9/30/2011 | $207,107 | $375,729 | $280,111 | | $95,618 | $302,725 | | |
| 103 | 10/31/2011 | $302,725 | $298,130 | $295,642 | | $2,488 | $305,213 | | |
| 104 | 11/30/2011 | $305,213 | $274,536 | $294,657 | | ($20,121) | $285,092 | | |
| 105 | 12/31/2011 | $285,092 | $289,902 | $323,559 | | ($33,657) | $251,435 | | |
| 106 | | | | | | | | | |
| 107 | | Period Cumulative Over/(Under) collection | | | | $162,342 | | | |
| 108 | | | | | | | | | |
| 109 | Forecast Cumulative Over/(Under) Collection at 12/31/2011 | | | | | | $251,435 | | |
| 110 | | | | | | | | | |
| 111 | | | | | | | | | |
| 112 | | | | | | | | | |
| 113 | | | | | | | | | |
| 114 | | | | | | | | | |
| 115 | | | | | | | | | |
| 116 | ***Footnote:*** | | | | | | | | |
| 117 | (1) Transfer to PPRF for SPE project of future rate reduction | | | | | | | | |

| | A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|---|
| 55 | | | | | | | | Schedule C-3 |
| 56 | | | **Transition Charge** | | | | | |
| 57 | | | | | | | | |
| 58 | | | **Revenue** | **Expense** | | **Monthly** | **Cumulative** | |
| 59 | Jan 2010 | $6,559 | $69,353 | $50,500 | | $18,853 | $25,412 | |
| 60 | Feb 2010 | $25,412 | $47,813 | $50,500 | | ($2,687) | $22,725 | |
| 61 | March 2010 | $22,725 | $44,141 | $50,500 | | ($6,359) | $16,365 | |
| 62 | April 2010 | $16,365 | $51,230 | $50,500 | | $730 | $17,096 | |
| 63 | May 2010 | $17,096 | $39,987 | $50,500 | | ($10,513) | $6,583 | |
| 64 | June 2010 | $6,583 | $47,127 | $50,500 | | ($3,373) | $3,210 | |
| 65 | July 2010 | $3,210 | $58,754 | $50,500 | | $8,254 | $11,464 | |
| 66 | August 2010 | $11,464 | $63,250 | $50,500 | | $12,750 | $24,213 | |
| 67 | Sept 2010 | $24,213 | $58,622 | $50,500 | | $8,122 | $32,335 | |
| 68 | Oct 2010 | $32,335 | $49,162 | $50,500 | | ($1,338) | $30,997 | |
| 69 | Nov 2010 | $30,997 | $43,473 | $50,500 | | ($7,027) | $23,970 | |
| 70 | Dec 2010 | $23,970 | $51,899 | $50,500 | | $1,399 | $25,369 | |
| 71 | | Period Cumulative Over/(Under) collection | | | | $18,810 | | |
| 72 | | | | | | | | |
| 73 | Forecast Cumulative Over/(Under) Collection at 12/31/2010 | | | | | | $25,369 | |
| 74 | | | | | | | | |
| 75 | | | | | | | | |
| 76 | | | | | | | | |
| 77 | | | | | | | | |
| 78 | | | | | | | | |
| 79 | | | | | | | | |
| 80 | | | **Transition Charge** | | | | | |
| 81 | | | | | | | | |
| 82 | | **Start Bal** | **Revenue** | **Expense** | | **Monthly** | **Cumulative** | |
| 83 | | | | | | | | |
| 84 | 1/31/2011 | $25,369 | $56,900 | $50,500 | | $6,400 | $31,769 | |
| 85 | 2/28/2011 | $31,769 | $54,788 | $50,500 | | $4,288 | $36,056 | |
| 86 | 3/31/2011 | $36,056 | $46,588 | $50,500 | | ($3,912) | $32,144 | |
| 87 | 4/30/2011 | $32,144 | $48,059 | $50,500 | | ($2,441) | $29,703 | |
| 88 | 5/31/2011 | $29,703 | $42,555 | $50,500 | | ($7,945) | $21,758 | |
| 89 | 6/30/2011 | $21,758 | $43,314 | $50,500 | | ($7,186) | $14,573 | |
| 90 | 7/31/2011 | $14,573 | $55,042 | $50,500 | | $4,542 | $19,115 | |
| 91 | 8/31/2011 | $19,115 | $57,931 | $50,500 | | $7,431 | $26,546 | |
| 92 | 9/30/2011 | $26,546 | $60,210 | $50,500 | | $9,710 | $36,257 | |
| 93 | 10/31/2011 | $36,257 | $47,775 | $50,500 | | ($2,725) | $33,532 | |
| 94 | 11/30/2011 | $33,532 | $43,994 | $50,500 | | ($6,506) | $27,026 | |
| 95 | 12/31/2011 | $27,026 | $46,457 | $50,500 | | ($4,043) | $22,983 | |
| 96 | | | | | | | | |
| 97 | | Period Cumulative Over/(Under) collection | | | | ($2,386) | | |
| 98 | | | | | | | | |
| 99 | Forecast Cumulative Over/(Under) Collection at 12/31/2011 | | | | | | $22,983 | |

| | A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|---|
| 64 | | | | | | | | Schedule C-4 | |
| 65 | | | | | | | | | |
| 66 | | | **Transmission Charge** | | | | | | |
| 67 | | | | | | | | | |
| 68 | Forecast Cumulative Over/(Under) Collection at 12/31/2009 | | | | | | $349,271 | | |
| 69 | Jan 2010 | Transfer to PPRF Account | | | | $ (200,000) | $149,271 | Per RIPUC order 12/23/09 **(1)** | |
| 70 | | | **Revenue** | **Expense** | | **Monthly** | **Cumulative** | | |
| 71 | Jan 2010 | $149,271 | $154,726 | $86,934 | | $ 67,793 | $217,064 | | |
| 72 | Feb 2010 | $217,064 | $82,944 | $113,084 | | $ (30,140) | $186,924 | | |
| 73 | Mar 2010 | $186,924 | $76,541 | $102,903 | | $ (26,363) | $160,561 | | |
| 74 | April 2010 | $160,561 | $88,835 | $104,593 | | $ (15,758) | $144,803 | | |
| 75 | May 2010 | $144,803 | $69,339 | $74,173 | | $ (4,833) | $139,970 | | |
| 76 | June 2010 | $139,970 | $81,719 | $90,787 | | $ (9,068) | $130,901 | | |
| 77 | July 2010 | $130,901 | $101,881 | $91,433 | | $ 10,448 | $141,350 | | |
| 78 | Aug 2010 | $141,350 | $109,677 | $102,672 | | $ 7,004 | $148,354 | | |
| 79 | Sept 2010 | $148,354 | $101,651 | $93,121 | | $ 8,530 | $156,884 | | |
| 80 | Oct 2010 | $156,884 | $85,248 | $91,606 | | $ (6,358) | $150,526 | | |
| 81 | Nov 2010 | $150,526 | $75,383 | $78,373 | | $ (2,989) | $147,537 | | |
| 82 | Dec 2010 | $147,537 | $89,994 | $100,824 | | $ (10,830) | $136,707 | | |
| 83 | | Period Cumulative Over/(Under) collection | | | | $ (12,564) | | | |
| 84 | | | | | | | | | |
| 85 | Forecast cumulative Over/(Under) Collection at 12/31/2010 | | | | | | $136,707 | | |
| 86 | | | | | | | | | |
| 87 | | | | | | | | | |
| 88 | | | | | | | | | |
| 89 | | | | | | | | | |
| 90 | | | | | | | | | |
| 91 | | | **Transmission Charge** | | | | | | |
| 92 | | | | | | | | | |
| 93 | | **Start Bal** | **Revenue** | **Expense** | | **Monthly** | **Cumulative** | | |
| 94 | 1/31/2011 | $136,707 | $102,534 | $109,574 | | ($7,039) | $129,667 | | |
| 95 | 2/28/2011 | $129,667 | $110,839 | $121,048 | | ($10,209) | $119,459 | | |
| 96 | 3/31/2011 | $119,459 | $94,246 | $115,843 | | ($21,597) | $97,862 | | |
| 97 | 4/30/2011 | $97,862 | $97,222 | $94,528 | | $2,694 | $100,556 | | |
| 98 | 5/31/2011 | $100,556 | $86,088 | $85,377 | | $711 | $101,267 | | |
| 99 | 6/30/2011 | $101,267 | $87,623 | $90,997 | | ($3,374) | $97,893 | | |
| 100 | 7/31/2011 | $97,893 | $111,349 | $96,748 | | $14,601 | $112,494 | | |
| 101 | 8/31/2011 | $112,494 | $117,193 | $111,325 | | $5,868 | $118,362 | | |
| 102 | 9/30/2011 | $118,362 | $121,804 | $88,939 | | $32,864 | $151,226 | | |
| 103 | 10/31/2011 | $151,226 | $96,648 | $106,466 | | ($9,818) | $141,408 | | |
| 104 | 11/30/2011 | $141,408 | $88,999 | $101,555 | | ($12,556) | $128,852 | | |
| 105 | 12/31/2011 | $128,852 | $93,980 | $104,248 | | ($10,268) | $118,584 | | |
| 106 | | | | | | | | | |
| 107 | | Period Cumulative Over/(Under) collection | | | | ($18,123) | | | |
| 108 | | | | | | | | | |
| 109 | Forecast cumulative Over/(Under) Collection at 12/31/2011 | | | | | | $118,584 | | |
| 110 | | | | | | | | | |
| 111 | | | | | | | | | |
| 112 | | | | | | | | | |
| 113 | | | | | | | | | |
| 114 | | | | | | | | | |
| 115 | | | | | | | | | |
| 116 | | | | | | | | | |
| 117 | | | | | | | | | |
| 118 | | | | | | | | | |
| 119 | | | | | | | | | |
| 120 | ***Footnote:*** | | | | | | | | |
| 121 | (1) Transfer to PPRF to increase balance to $500,000 | | | | | | | | |

## Reconciliation of Forecast to Actual

| Month | Budget (1) | Actual | Difference | Energy (MWH) Budget (1) | Energy (MWH) Actual | Difference (Energy) | Actual Cost MWH | Budget Cost MWH |
|---|---|---|---|---|---|---|---|---|
| Jan 2011 | $475,934 | $471,428 | ($4,506) | 4,938 | 5,105 | 167 | $92.34 | $96.38 |
| Feb 2011 | $441,164 | $447,989 | $6,825 | 4,318 | 4,410 | 92 | $101.59 | $102.17 |
| Mar 2011 | $442,489 | $462,952 | $20,463 | 4,463 | 4,759 | 296 | $97.28 | $99.15 |
| Apr 2011 | $461,180 | $428,074 | ($33,106) | 3,999 | 4,040 | 41 | $105.97 | $115.32 |
| May 2011 | $426,799 | $436,527 | $9,728 | 4,142 | 4,093 | (49) | $106.65 | $103.04 |
| Jun 2011 | $469,553 | $442,877 | ($26,676) | 4,584 | 4,638 | 54 | $95.49 | $102.43 |
| Jul 2011 | $503,077 | $494,050 | ($9,027) | 5,432 | 5,679 | 247 | $87.00 | $92.61 |
| Aug 2011 | $519,358 | $472,940 | ($46,418) | 5,210 | 4,892 | (318) | $96.67 | $99.68 |
| Sep 2011 | $464,149 | $419,551 | ($44,598) | 4,354 | 4,506 | 152 | $93.11 | $106.60 |
| Oct 2011 (Revised) | $ 452,608 | $452,608 | $0 | 4,350 | 4,350 | 0 | $104.05 | $104.05 |
| Nov 2011 (Revised) | $446,712 | $446,712 | $0 | 4,407 | 4,407 | 0 | $101.36 | $101.36 |
| Dec 2011 (Revised) | $478,307 | $478,307 | $0 | 4,988 | 4,988 | 0 | $95.89 | $95.89 |
| Total | $5,581,330 | $5,454,015 | ($127,315) | 55,185 | 55,867 | 682 | $97.63 | $101.14 |
| Original Forecast | $5,593,165 | | | | | | | |
| | ($11,835) | | | | "Average" MWH cost | | $97.63 | $101.14 |

(1) From 12/2010 filing, Schedule F

D

| | A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 64 | | | | | | | | | | | Schedule E | |
| 65 | | | | | | | | | | | | |
| 66 | | | **Summary of Energy Sales to Customers Fiscal Year 2010** | | | | | | | | | |
| 67 | | | | | | | | | | | | |
| 68 | | | **2010** | | **2009** | | **2008** | | | | | |
| 69 | | | | | | | | | | | | |
| 70 | January | Actual | 5,100 | | 5,337 | | 4,444 | | | 4,961 | | |
| 71 | February | Actual | 4,128 | | 4,363 | | 4,594 | | | 4,362 | | |
| 72 | March | Actual | 3,812 | | 4,183 | | 4,069 | | | 4,021 | | |
| 73 | April | Actual | 4,424 | | 3,696 | | 3,937 | | | 4,019 | | |
| 74 | May | Actual | 3,453 | | 4,014 | | 3,970 | | | 3,813 | | |
| 75 | June | Actual | 4,070 | | 3,577 | | 3,616 | | | 3,754 | | |
| 76 | July | Actual | 5,074 | | 3,951 | | 4,599 | | | 4,541 | | |
| 77 | August | Actual | 5,462 | | 4,876 | | 5,366 | | | 5,235 | | |
| 78 | Sept | Actual | 5,062 | | 4,713 | | 4,153 | | | 4,643 | | |
| 79 | Oct | Actual | 4,245 | | 4,203 | | 4,190 | | | 4,213 | | |
| 80 | Nov | Actual | 3,754 | | 3,954 | | 4,145 | | | 3,951 | | |
| 81 | Dec | Actual | 4,482 | | 3,849 | | 3,611 | | | 3,981 | | |
| 82 | | | | | | | | | | | | |
| 83 | | | 53,066 | | 50,718 | | 50,693 | | | 51,492 | | |
| 84 | | (Schedule A, Line 138) | | | | | | | | | | |
| 85 | | | | | | | | | | | | |
| 86 | | | | | | | | | | | | |
| 87 | Annual Total Average Sales | | | | | | | | | 51,492 | | |
| 88 | Growth Factor | 1% | | | | | | | | 515 | | |
| 89 | | | | | | | | | | | | |
| 90 | Annual Forecast Sales | | | | | | | | | 52,007 | | |
| 91 | | | | | | | | | | | | |
| 92 | | | | | | | | | | | | |
| 93 | | | | | | | | | | | | |
| 94 | | | | | | | | | | | | |
| 95 | | | **Summary of Energy Sales to Customers Fiscal Year 2011** | | | | | | | | | |
| 96 | | | | | | | | | | | | |
| 97 | | | **2011** | | **2010** | | **2009** | | | **3-Year Average** | | |
| 98 | | | | | | | | | | | | |
| 99 | January | | 4,940 | | 5,100 | | 5,337 | | | 5,126 | | |
| 100 | February | | 4,840 | | 4,128 | | 4,363 | | | 4,444 | | |
| 101 | March | | 4,116 | | 3,812 | | 4,183 | | | 4,037 | | |
| 102 | April | | 4,245 | | 4,424 | | 3,696 | | | 4,122 | | |
| 103 | May | | 3,759 | | 3,453 | | 4,014 | | | 3,742 | | |
| 104 | June | | 3,826 | | 4,070 | | 3,577 | | | 3,824 | | |
| 105 | July | | 4,862 | | 5,074 | | 3,951 | | | 4,629 | | |
| 106 | August | | 5,118 | | 5,462 | | 4,876 | | | 5,152 | | |
| 107 | September | | 5,319 | | 5,062 | | 4,713 | | | 5,031 | | |
| 108 | October | | 4,213 | **(1)** | 4,245 | | 4,203 | | | 4,220 | | |
| 109 | November | | 3,951 | **(1)** | 3,754 | | 3,954 | | | 3,886 | | |
| 110 | December | | 3,981 | **(1)** | 4,482 | | 3,849 | | | 4,104 | | |
| 111 | | | | | | | | | | | | |
| 112 | | | 53,170 | | 53,066 | | 50,718 | | | 52,318 | | |
| 113 | | | | | | | | | | | | |
| 114 | | | | | | | | | | | | |
| 115 | | | | | | | | | | | | |
| 116 | Annual Total Sales - Three Year Average | | | | | | | | | 52,318 | | |
| 117 | No Growth Factor | | | | | | | | | 0 | | |
| 118 | Annual Forecast Sales - 2012 | | | | | | | | | 52,318 | | |
| 119 | | | | | | | | | | | | |
| 120 | | | | | | | | | | | | |
| 121 | ***Footnote:*** | | | | | | | | | | | |
| 122 | (1) See Three Year Average, above for estimated sales | | | | | | | | | | | |

| | A | B | Jan 2012 (MWH) Forecast | Feb 2012 (MWH) Forecast | Mar 2012 (MWH) Forecast | Apr 2012 (MWH) Forecast | May 2012 (MWH) Forecast | Jun 2012 (MWH) Forecast | Jul 2012 (MWH) Forecast | Aug 2012 (MWH) Forecast | Sept 2012 (MWH) Forecast | Oct 2012 (MWH) Forecast | Nov 2012 (MWH) Forecast | Dec 2012 (MWH) Forecast | Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | Pascoag Utility District | | | | | | | | | | | | | |
| 2 | | Forecast Purchased Power Costs (1) | | | | | | | | | | | | | |
| 3 | | **Resources** | | | | | | | | | | | | | |
| 6 | | NYPA - Firm | 1,391 | 1,302 | 1,391 | 1,346 | 1,391 | 1,346 | 1,391 | 1,391 | 1,346 | 1,391 | 1,346 | 1,391 | 16,423 |
| 7 | | Seabrook | 970 | 907 | 970 | 939 | 970 | 939 | 970 | 970 | 939 | - | 939 | 970 | 10,483 |
| 8 | **Sub-total Base** | | 2,361 | 2,209 | 2,361 | 2,285 | 2,361 | 2,285 | 2,361 | 2,361 | 2,285 | 1,391 | 2,285 | 2,361 | 26,906 |
| 9 | | Capacity Market Sales | | | | | | | | | | | | | - |
| 10 | | Capacity Market Purchases | | | | | | | | | | | | | |
| 11 | | Dominion Capacity Purchase | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | | Energy Purchases | - | - | - | - | - | - | - | - | - | - | - | - | |
| 13 | | Miller Hydro | 129 | 112 | 151 | 188 | 181 | 145 | 95 | 84 | 68 | 104 | 137 | 137 | 1,531 |
| 14 | | Spruce Mt. | 180 | 190 | 176 | 94 | 127 | 149 | 93 | 97 | 125 | 154 | 160 | 186 | 1,731 |
| 15 | | Constellation Purchase | 2441 | 2142 | 1947 | 1498 | 1654 | 2362 | 3400 | 2754 | 2107 | 1,730 | 1876 | 2,426 | 26,337 |
| 16 | **Sub-total Intermediate** | | 2,750 | 2,444 | 2,274 | 1,780 | 1,962 | 2,656 | 3,588 | 2,935 | 2,300 | 1,988 | 2,173 | 2,749 | 29,599 |
| 17 | | NYPA - Peak | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 108 |
| 18 | **Sub-total Peaking** | | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 108 |
| 19 | | ISO Energy Net Interchange | (86) | (330) | (147) | (31) | (122) | (394) | (526) | (96) | (206) | 932 | (72) | (92) | (1,170) |
| 20 | | **Total MWH Purchased** | 5,034 | 4,332 | 4,497 | 4,043 | 4,210 | 4,556 | 5,432 | 5,209 | 4,388 | 4,320 | 4,395 | 5,027 | 55,443 |
| 21 | | **Purchased Power Cost** | | | | | | | | | | | | | |
| 22 | | NYPA Firm | $ 15,315 | $ 14,873 | $ 15,315 | $ 15,094 | $ 15,579 | $ 15,358 | $ 15,579 | $ 15,579 | $ 15,358 | $ 15,579 | $ 15,358 | $ 15,579 | $ 184,566 |
| 23 | (T) | NYPA Transmission | $ 28,000 | $ 38,000 | $ 28,000 | $ 20,600 | $ 14,600 | $ 14,600 | $ 16,600 | $ 18,600 | $ 15,600 | $ 20,600 | $ 20,600 | $ 18,600 | $ 254,400 |
| 24 | (2) | Seabrook | $ 90,468 | $ 89,913 | $ 90,468 | $ 90,191 | $ 98,168 | $ 97,891 | $ 90,968 | $ 90,968 | $ 90,668 | $ 81,667 | $ 90,668 | $ 90,968 | $ 1,093,006 |
| 25 | (T) | Seabrook Transmission | $ 600 | $ 600 | $ 600 | $ 600 | $ 600 | $ 600 | $ 600 | $ 600 | $ 600 | $ 600 | $ 600 | $ 600 | $ 7,200 |
| 26 | **Sub-total Base** | | $ 134,383 | $ 143,386 | $ 134,383 | $ 126,485 | $ 128,947 | $ 128,449 | $ 123,747 | $ 125,747 | $ 122,226 | $ 118,446 | $ 127,226 | $ 125,747 | $ 1,539,172 |
| 27 | | Capacity Market Sales | ($10,800) | ($10,800) | ($10,800) | ($10,800) | ($10,800) | ($8,640) | ($8,640) | ($8,640) | ($8,640) | ($8,640) | ($8,640) | ($8,640) | ($114,480) |
| 28 | | Capacity Market Purchases | $ 42,741 | $ 42,741 | $ 42,741 | $ 42,741 | $ 42,741 | $ 34,193 | $ 34,193 | $ 34,193 | $ 34,193 | $ 34,193 | $ 34,193 | $ 34,193 | $ 453,056 |
| 29 | | Dominion Capacity Purchase | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 168,480 |
| 30 | | Energy Purchases | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 31 | | Miller Hydro | $ 8,205 | $ 7,098 | $ 9,561 | $ 11,961 | $ 11,468 | $ 9,195 | $ 6,031 | $ 5,352 | $ 4,314 | $ 6,629 | $ 8,693 | $ 8,730 | $ 97,237 |
| 32 | | Spruce Mt. | $ 17,892 | $ 18,877 | $ 17,446 | $ 9,337 | $ 12,629 | $ 14,774 | $ 9,210 | $ 9,612 | $ 12,391 | $ 15,273 | $ 15,854 | $ 18,442 | $ 171,737 |
| 33 | | Constellation Purchase | $ 146,220 | $ 128,300 | $ 116,607 | $ 89,728 | $ 99,099 | $ 141,482 | $ 203,665 | $ 164,992 | $ 126,209 | $ 103,619 | $ 112,365 | $ 145,347 | $ 1,577,633 |
| 34 | | ISO Energy Net Interchange | $ (4,635) | $ (17,699) | $ (5,575) | $ (1,050) | $ (4,151) | $ (13,410) | $ (19,398) | $ (3,528) | $ (6,923) | $ 33,024 | $ (2,725) | $ (4,188) | $ (50,258) |
| 35 | **Sub-total Intermediate** | | $ 213,663 | $ 182,557 | $ 184,020 | $ 155,957 | $ 165,026 | $ 191,634 | $ 239,101 | $ 216,021 | $ 175,584 | $ 198,138 | $ 173,780 | $ 207,924 | $ 2,303,405 |
| 36 | | NYPA - Peak | $ 431 | $ 428 | $ 431 | $ 429 | $ 443 | $ 441 | $ 443 | $ 443 | $ 441 | $ 443 | $ 441 | $ 443 | $ 5,257 |
| 37 | (T) | NYPA - Peaking Transmission | $ 400 | $ 400 | $ 400 | $ 400 | $ 400 | $ 400 | $ 400 | $ 400 | $ 400 | $ 400 | $ 400 | $ 400 | $ 4,800 |
| 38 | **Sub-total Peaking** | | $ 831 | $ 828 | $ 831 | $ 829 | $ 843 | $ 841 | $ 843 | $ 843 | $ 841 | $ 843 | $ 841 | $ 843 | $ 10,057 |
| 39 | | ISO Energy Net Interchange | | | | | | | | | | | | | $0 |
| 40 | | | | | | | | | | | | | | | $ - |
| 41 | | Service Billing | $ 100 | $ 100 | $ 100 | $ 100 | $ 100 | $ 100 | $ 100 | $ 100 | $ 100 | $ 100 | $ 100 | $ 100 | $ 1,200 |
| 42 | (T) | Hydro Quebec | $ 1,500 | $ 1,500 | $ 1,500 | $ 1,500 | $ 1,500 | $ 1,500 | $ 1,500 | $ 1,500 | $ 1,500 | $ 1,500 | $ 1,500 | $ 1,500 | $ 18,000 |
| 43 | | ENE All Requir/Supply | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 76,632 |
| 44 | | ISO Annual Fee | $ 5,360 | $ - | $ - | | | | | | | | | | $ 5,360 |
| 45 | | ISO Load Based Charges | $ 4,703 | $ 3,596 | $ 2,616 | $ 3,580 | $ 2,411 | $ 2,505 | $ 3,532 | $ 10,578 | $ 8,099 | $ 2,152 | $ 1,876 | $ 3,062 | $ 48,710 |
| 46 | | ISO Scheduled Charges | $ 1,667 | $ 5,999 | $ 5,561 | $ 5,887 | $ 5,358 | $ 5,572 | $ 5,755 | $ 9,197 | $ 7,884 | $ 7,952 | $ 6,030 | $ 6,389 | $ 73,251 |
| 47 | (T) | NEPOOL OATT Charge | $ 63,149 | $ 61,555 | $ 61,425 | $ 54,500 | $ 48,211 | $ 55,404 | $ 67,122 | $ 88,942 | $ 76,708 | $ 80,986 | $ 57,027 | $ 63,555 | $ 778,584 |
| 48 | (T) | Network Trans Service (NGRID) | $ 20,000 | $ 20,000 | $ 20,000 | $ 20,000 | $ 20,000 | $ 20,000 | $ 20,000 | $ 20,000 | $ 20,000 | $ 20,000 | $ 20,000 | $ 20,000 | $ 240,000 |
| 49 | (T) | DAF Charge (NGRID) | $ 6,600 | $ 6,600 | $ 6,600 | $ 6,600 | $ 6,600 | $ 6,600 | $ 6,600 | $ 6,600 | $ 6,600 | $ 7,400 | $ 7,400 | $ 7,400 | $ 81,600 |
| 50 | | Total (non-transmission) | $ 18,216 | $ 16,081 | $ 14,663 | $ 15,953 | $ 14,255 | $ 14,563 | $ 15,773 | $ 26,261 | $ 22,469 | $ 16,590 | $ 14,392 | $ 15,937 | $ 205,153 |
| 51 | | Transmission (T) subtotal | $ 91,249 | $ 89,655 | $ 89,525 | $ 82,600 | $ 76,311 | $ 83,504 | $ 95,222 | $ 117,042 | $ 104,808 | $ 109,886 | $ 85,927 | $ 92,455 | $ 1,118,184 |
| 52 | | Total | $ 109,465 | $ 105,736 | $ 104,188 | $ 98,553 | $ 90,566 | $ 98,067 | $ 110,995 | $ 143,303 | $ 127,277 | $ 126,476 | $ 100,319 | $ 108,392 | $ 1,323,337 |
| 53 | | | | | | | | | | | | | | | |
| 54 | Total | All Transmission | $ 120,249 | $ 128,655 | $ 118,525 | $ 104,200 | $ 91,911 | $ 99,104 | $ 112,822 | $ 136,642 | $ 121,408 | $ 131,486 | $ 107,527 | $ 112,055 | $ 1,384,584 |
| 55 | Total | Energy (Fixed and Variable) | $ 338,093 | $ 303,852 | $ 304,897 | $ 277,624 | $ 293,471 | $ 319,887 | $ 361,864 | $ 349,272 | $ 304,520 | $ 312,417 | $ 294,639 | $ 330,851 | $ 3,791,387 |
| 56 | Total | Total Costs for Period | 458,342 | 432,507 | 423,422 | 381,824 | 385,382 | 418,991 | 474,686 | 485,914 | 425,928 | 443,903 | 402,166 | 442,906 | $ 5,175,971 |
| 57 | | | (1) | Please see, Energy New England Bulk Power Cost Projections, Schedule G-1 to G-13 | | | | | | | | | | | |
| 58 | | | (2) | The total for Seabrook (Project 6) includes the Surplus Fund Credit. (Based on MMWEC's Surplus Fund reconciliaiton dated July 20, 2011.) | | | | | | | | | | | |
| 59 | | | (T) | Indicates Transmission Charges | | | | | | | | | | | |

Pascoag Utility District

Restated Forecast Purchased Power Costs

| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 64 | | | Jan 2012 | Feb 2012 | Mar 2012 | Apr 2012 | May 2012 | Jun 2012 | Jul 2012 | Aug 2012 | Sept 2012 | Oct 2012 | Nov 2012 | Dec 2012 | Period Total |
| 65 | Annual Identified MMWEC Cost (3) | | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | $ 603,000 |
| 66 | Monthly Assessment | | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 603,000 |
| 67 | Less Cumulative Carry Over | | ($1,915) | ($1,915) | ($1,915) | ($1,915) | ($1,915) | ($1,915) | ($1,915) | ($1,915) | ($1,915) | ($1,915) | ($1,915) | ($1,915) | $ (22,983) |
| 68 | | (Schedule C-3, Line 47 | | | | | | | | | | | | | |
| 69 | Restated Transition Cost | | 48,335 | 48,335 | 48,335 | 48,335 | 48,335 | 48,335 | 48,335 | 48,335 | 48,335 | 48,335 | 48,335 | 48,335 | $ 580,017 |
| 70 | | | | | | | | | | | | | | | |
| 71 | Transmission | | | | | | | | | | | | | | |
| 72 | | Transmission | $ 120,249 | $ 128,655 | $ 118,525 | $ 104,200 | $ 91,911 | $ 99,104 | $ 112,822 | $ 136,642 | $ 121,408 | $ 131,486 | $ 107,527 | $ 112,055 | $ 1,384,584 |
| 73 | Net Transmission | | $ 120,249 | $ 128,655 | $ 118,525 | $ 104,200 | $ 91,911 | $ 99,104 | $ 112,822 | $ 136,642 | $ 121,408 | $ 131,486 | $ 107,527 | $ 112,055 | $ 1,384,584 |
| 74 | | | | | | | | | | | | | | | |
| 75 | Restated Costs (Dollars) - Standard Offer | | | | | | | | | | | | | | |
| 76 | | NYPA Firm | $ 15,315 | $ 14,873 | $ 15,315 | $ 15,094 | $ 15,579 | $ 15,358 | $ 15,579 | $ 15,579 | $ 15,358 | $ 15,579 | $ 15,358 | $ 15,579 | $ 184,566 |
| 77 | | NYPA - Peak | $ 431 | $ 428 | $ 431 | $ 429 | $ 443 | $ 441 | $ 443 | $ 443 | $ 441 | $ 443 | $ 441 | $ 443 | $ 5,257 |
| 78 | | Miller Hydro | $ 8,205 | $ 7,098 | $ 9,561 | $ 11,961 | $ 11,468 | $ 9,195 | $ 6,031 | $ 5,352 | $ 4,314 | $ 6,629 | $ 8,693 | $ 8,730 | $ 97,237 |
| 79 | | Capacity Market Sales | $ (10,800) | ($10,800) | ($10,800) | ($10,800) | ($10,800) | ($8,640) | ($8,640) | ($8,640) | ($8,640) | ($8,640) | ($8,640) | ($8,640) | ($114,480) |
| 80 | | Dominion Capacity Purchases | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $ 14,040 | $168,480 |
| 81 | | Spruce Mnt. | $ 17,892 | $ 18,877 | $ 17,446 | $ 9,337 | $ 12,629 | $ 14,774 | $ 9,210 | $ 9,612 | $ 12,391 | $ 15,273 | $ 15,854 | $ 18,442 | $ 171,737 |
| 82 | | ISO Energy Interchange | $ (4,635) | $ (17,699) | $ (5,575) | $ (1,050) | $ (4,151) | $ (13,410) | $ (19,398) | $ (3,528) | $ (6,923) | $ 33,024 | $ (2,725) | $ (4,188) | $ (50,258) |
| 83 | | Capacity Market Purchase | $ 42,741 | $ 42,741 | $ 42,741 | $ 42,741 | $ 42,741 | $ 34,193 | $ 34,193 | $ 34,193 | $ 34,193 | $ 34,193 | $ 34,193 | $ 34,193 | $ 453,056 |
| 84 | | Constellation Purchase | $ 146,220 | $ 128,300 | $ 116,607 | $ 89,728 | $ 99,099 | $ 141,482 | $ 203,665 | $ 164,992 | $ 126,209 | $ 103,619 | $ 112,365 | $ 145,347 | $1,577,633 |
| 85 | | Project 6 (total billing) | $ 90,468 | $ 89,913 | $ 90,468 | $ 90,191 | $ 98,168 | $ 97,891 | $ 90,968 | $ 90,968 | $ 90,668 | $ 81,667 | $ 90,668 | $ 90,968 | $1,093,006 |
| 86 | | Service Billing | $ 100 | $ 100 | $ 100 | $ 100 | $ 100 | $ 100 | $ 100 | $ 100 | $ 100 | $ 100 | $ 100 | $ 100 | $ 1,200 |
| 87 | | Energy Purchase | | | | | | | | | | $ - | $ - | $ - | $ - |
| 88 | | ISO Annual Fee | $ 5,360 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 5,360 |
| 89 | | ISO Load Based Charges | $ 4,703 | $ 3,596 | $ 2,616 | $ 3,580 | $ 2,411 | $ 2,505 | $ 3,532 | $ 10,578 | $ 8,099 | $ 2,152 | $ 1,876 | $ 3,062 | $ 48,710 |
| 90 | | ISO Scheduled Charges | $ 1,667 | $ 5,999 | $ 5,561 | $ 5,887 | $ 5,358 | $ 5,572 | $ 5,755 | $ 9,197 | $ 7,884 | $ 7,952 | $ 6,030 | $ 6,389 | $ 73,251 |
| 91 | | ENE Expenses | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 6,386 | $ 76,632 |
| 92 | | Sub-Total | $ 338,093 | $ 303,852 | $ 304,897 | $ 277,624 | $ 293,471 | $ 319,887 | $ 361,864 | $ 349,272 | $ 304,520 | $ 312,417 | $ 294,639 | $ 330,851 | $ 3,791,387 |
| 93 | Less Identified Project 6 Transition | | $ (50,250) | $ (50,250) | $ (50,250) | $ (50,250) | $ (50,250) | $ (50,250) | $ (50,250) | $ (50,250) | $ (50,250) | $ (50,250) | $ (50,250) | $ (50,250) | ($603,000) |
| 94 | Restated Costs - Standard Offer | | $ 287,843 | $ 253,602 | $ 254,647 | $ 227,374 | $ 243,221 | $ 269,637 | $ 311,614 | $ 299,022 | $ 254,270 | $ 262,167 | $ 244,389 | $ 280,601 | $ 3,188,387 |
| 95 | | | | | | | | | | | | | | | |
| 96 | Restated Costs: | | | | | | | | | | | | | | |
| 97 | Transition | | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 50,250 | $ 603,000 |
| 98 | Transmission | | $ 120,249 | $ 128,655 | $ 118,525 | $ 104,200 | $ 91,911 | $ 99,104 | $ 112,822 | $ 136,642 | $ 121,408 | $ 131,486 | $ 107,527 | $ 112,055 | $ 1,384,584 |
| 99 | Standard Offer | | $ 287,843 | 253,602 | $ 254,647 | $ 227,374 | $ 243,221 | $ 269,637 | $ 311,614 | $ 299,022 | $ 254,270 | $ 262,167 | $ 244,389 | $ 280,601 | $ 3,188,387 |
| 100 | Total Restated Costs | | $ 458,342 | $ 432,507 | $ 423,422 | $ 381,824 | $ 385,382 | $ 418,991 | $ 474,686 | $ 485,914 | $ 425,928 | $ 443,903 | $ 402,166 | $ 442,906 | $ 5,175,971 |
| 101 | | | | | | | | | | | | | | | |
| 102 | | | Jan 2012 | Feb 2012 | Mar 2012 | Apr 2012 | May 2012 | Jun 2012 | Jul 2012 | Aug 2012 | Sept 2012 | Oct 2012 | Nov 2012 | Dec 2012 | |
| 103 | | | 3 Yr-Avg | 3 Yr-Avg | 3 Yr-Avg | 3 Yr-Avg | 3 Yr-Avg | 3 Yr-Avg | 3 Yr-Avg | 3 Yr-Avg | 3 Yr-Avg | 3 Yr-Avg | 3 Yr-Avg | 3 Yr-Avg | |
| 104 | Actual Sales Previous Period (4) | | 5,126 | 4,444 | 4,037 | 4,122 | 3,742 | 3,824 | 4,629 | 5,152 | 5,031 | 4,220 | 3,886 | 4,104 | 52,318 |
| 105 | No Growth Factor | | | | | | | | | | | | | | - |
| 106 | Estimated Sales | | 5,126 | 4,444 | 4,037 | 4,122 | 3,742 | 3,824 | 4,629 | 5,152 | 5,031 | 4,220 | 3,886 | 4,104 | 52,318 |
| 107 | | | | | | | | | | | | | | | |
| 108 | | Transition | $ 9.80 | $ 11.31 | $ 12.45 | $ 12.19 | $ 13.43 | $ 13.14 | $ 10.86 | $ 9.75 | $ 9.99 | $ 11.91 | $ 12.93 | $ 12.24 | $ 11.53 |
| 109 | | Transmission | $ 23.46 | $ 28.95 | $ 29.36 | $ 25.28 | $ 24.56 | $ 25.91 | $ 24.37 | $ 26.52 | $ 24.13 | $ 31.15 | $ 27.67 | $ 27.30 | $ 26.46 |
| 110 | | Standard Offer | $ 56.15 | $ 57.07 | $ 63.08 | $ 55.16 | $ 64.99 | $ 70.51 | $ 67.32 | $ 58.04 | $ 50.54 | $ 62.12 | $ 62.88 | $ 68.37 | $ 60.94 |
| 111 | | Total | $ 89.42 | $ 97.33 | $ 104.89 | $ 92.63 | $ 102.98 | $ 109.56 | $ 102.55 | $ 94.32 | $ 84.65 | $ 105.18 | 103.48 | 107.92 | $ 98.93 |
| 112 | | | | | | | | | | | | | | | |
| 113 | | | | | | | | | | | | | | | |
| 114 | (3) | From Pascoag's Audited Financial Statements, FY ending 12/31/2010; Contingent Liability - MMWEC Footnote, Page 19. For 2012, the total annual cost is $603,000 | | | | | | | | | | | | | |
| 115 | (4) | From Schedule E | | | | | | | | | | | | | |
| 116 | | | | | | | | | | | | | | | |
| 117 | (T) | Indicates Transmission Charges | | | | | | | | | | | | | |

Schedule F-2

Schedule G-1

# Bulk Powe st Projections
## Pascoag Utility District
## January-12

System Peak Demand (KW) 9,889
System Energy Requirements (MWH) 5,035

| RESOURCES | (KW) | FIXED COSTS Budget $/KW-MO | FIXED COSTS Budget ($) | CF (%) | ENERGY VARIABLE COSTS MWH | ENERGY VARIABLE COSTS Budget ($/MWH) | ENERGY VARIABLE COSTS ($) | TRANS. COST Budget ($) | TOTAL COSTS Budget ($) | TOTAL COSTS Budget ($/MWH) |
|---|---|---|---|---|---|---|---|---|---|---|
| NYPA Firm | 2,200 | 3.85 | 8,470 | 85 | 1,391 | 4.92 | 6,845 | 28,000 | 43,315 | 31.13 |
| Seabrook (Project 6) | 1,321 | 67.80 | 81,864 | 99 | 970 | 8.87 | 8,604 | 600 | 91,068 | 93.88 |
| SUBTOTAL - BASE | 3,521 | | 90,334 | | 2,361 | | 15,449 | 28,600 | 134,383 | 56.91 |
| Capacity Market Sales | -2,400 | 4.50 | -10,800 | | | | | | -10,800 | N/A |
| Capacity Market Purchases | 9,498 | 4.50 | 42,741 | | 0 | 0.00 | 0 | | 42,741 | N/A |
| Dominion Capacity Purchase | 2,400 | 5.85 | 14,040 | | | | | | 14,040 | N/A |
| Energy Purchase | | | 0 | | 0 | 0.00 | 0 | | 0 | #DIV/0! |
| Miller Hydro Purchase | | | | | 129 | 63.50 | 8,205 | | 8,205 | 63.50 |
| Spruce Mtn Purchase | | | | | 180 | 99.25 | 17,892 | | 17,892 | 99.25 |
| Constellation "Bal Power" Purchase | | | 0 | | 2,441 | 59.90 | 146,220 | | 146,220 | 59.90 |
| SUBTOTAL - INTERMEDIATE | 11,898 | | 45,981 | | 2,751 | | 172,317 | 0 | 218,298 | 79.37 |
| NYPA Peak | 100 | 3.85 | 385 | 13 | 9 | 4.92 | 46 | 400 | 831 | 89.33 |
| SUBTOTAL - PEAKING | 100 | | 385 | | 9 | | 46 | 400 | 831 | 89.33 |
| ISO Energy Net Interchange | | | | | -86 | 53.69 | -4,635 | | -4,635 | 53.69 |
| Service Billing | | | 100 | | | | | | 100 | 0.02 |
| Hydro Quebec I | 934 | | | | | | | 1,500 | 1,500 | 0.30 |
| ENE All Req/Short Supply | | | 6,386 | | | | | | 6,386 | 1.27 |
| ISO Annual Fee | | | 5,360 | | | | | | 5,360 | 1.06 |
| ISO Load Based Charges | | | 4,703 | | | | | | 4,703 | 0.93 |
| ISO Scheduled Charges | | | 1,667 | | | | | | 1,667 | 0.33 |
| NEPOOL OATT Charge | | | 0 | | | | | 63,149 | 63,149 | 12.54 |
| Network Transmission Service (NGRID) | | | 0 | | | | | 20,000 | 20,000 | 3.97 |
| DAF (Subtransmission Ch) | | | 0 | | | | | 6,600 | 6,600 | 1.31 |
| SUBTOTAL - OTHER CHARGE | 934 | | 18,216 | | 0 | | 0 | 91,249 | 109,465 | 21.74 |
| TOTAL | 3,434 | | 154,916 | | 5,035 | | 183,177 | 120,249 | 458,343 | 91.03 |

E= $338,093 T= 120,249 = $458,342

Schedule G-2

**Bulk Powe[illegible] [illegible]st Projections**
**Pascoag Utility District**
**February-12**

| RESOURCES | (KW) | FIXED COSTS Budget ($/KW-MO) | FIXED COSTS ($) | CF (%) | ENERGY VARIABLE COSTS MWH | ENERGY VARIABLE COSTS Budget ($/MWH) | ENERGY VARIABLE COSTS ($) | TRANS. COST Budget ($) | TOTAL COSTS Budget ($) | TOTAL COSTS ($/MWH) |
|---|---|---|---|---|---|---|---|---|---|---|
| System Peak Demand (KW) | | 9,869 | | | | | | | | |
| System Energy Requirements (MWH) | | 4,332 | | | | | | | | |
| NYPA Firm | 2,200 | 3.85 | 8,470 | 85 | 1,302 | 4.92 | 6,403 | 38,000 | 52,873 | 40.62 |
| Seabrook (Project 6) | 1,321 | 67.80 | 81,864 | 98.7 | 907 | 8.87 | 8,049 | 600 | 90,513 | 99.74 |
| SUBTOTAL - BASE | 3,521 | | 90,334 | | 2,209 ✓ | | 14,453 | 38,600 | 143,386 ✓ | 64.91 |
| Capacity Market Sales | -2,400 | 4.50 | -10,800 | | | | | | -10,800 | N/A |
| Capacity Market Purchases | 9,498 | 4.50 | 42,741 | | 0 | 0.00 | 0 | | 42,741 | N/A |
| Dominion Capacity Purchase | 2,400 | 5.85 | 14,040 | | | | | | 14,040 | N/A |
| Energy Purchase | | | 0 | | 0 | 0.00 | 0 | | 0 | #DIV/0! |
| Miller Hydro Purchase | | | | | 112 | 63.50 | 7,098 | | 7,098 | 63.50 |
| Spruce Mtn Purchase | | | | | 190 | 99.25 | 18,877 | | 18,877 | 99.25 |
| Constellation "Bal Power" Purchase | | | 0 | | 2,142 | 59.90 | 128,300 | | 128,300 | 59.90 |
| SUBTOTAL - INTERMEDIATE | 11,898 | | 45,981 | | 2,444 ✓ | | 154,276 | 0 | 200,257 | 81.94 |
| NYPA Peak | 100 | 3.85 | 385 | 12.5 | 9 | 4.92 | 43 | 400 | 828 | 95.15 |
| SUBTOTAL - PEAKING | 100 | | 385 | | 9 | | 43 | 400 | 828 | 95.15 |
| ISO Energy Net Interchange | | | | | -330 | 53.69 | -17,699 | | -17,699 | 53.69 |
| Service Billing | | | 100 | | | | | | 100 | 0.02 |
| Hydro Quebec I | 934 | | | | | | | 1,500 | 1,500 | 0.35 |
| ENE All Req/Short Supply | | | 6,386 | | | | | | 6,386 | 1.47 |
| ISO Annual Fee | | | | | | | | | 0 | 0.00 |
| ISO Load Based Charges | | | 3,596 | | | | | | 3,596 | 0.83 |
| ISO Scheduled Charges | | | 5,999 | | | | | | 5,999 | 1.38 |
| NEPOOL OATT Charge | | | 0 | | | | | 61,555 | 61,555 | 14.21 |
| Network Transmission Service (NGRID) | | | 0 | | | | | 20,000 | 20,000 | 4.62 |
| DAF (Subtransmission Ch) | | | 0 | | | | | 6,600 | 6,600 | 1.52 |
| SUBTOTAL - OTHER CHARGE | 934 | | 16,081 | | 0 | | 0 | 89,655 | 105,735 | 24.41 |
| TOTAL | 3,434 | | 152,780 | | 4,332 // ga | | 151,072 | 128,655 ✓ | 432,507 // ga | 99.84 |

E= $303,852 T= $128,655= $432,507//

Schedule G-3

# Bulk Powe st Projections
## Pascoag Utility District
## March-12

System Peak Demand (KW) 8,756
System Energy Requirements (MWH) 4,497

| RESOURCES | (KW) | FIXED COSTS Budget (\$/KW-MO) | FIXED COSTS ($) | CF (%) | ENERGY VARIABLE COSTS MWH | Budget (\$/MWH) | ($) | TRANS. COST Budget ($) | TOTAL COSTS Budget ($) | ($/MWH) |
|---|---|---|---|---|---|---|---|---|---|---|
| NYPA Firm | 2,200 | 3.85 | 8,470 | 85 | 1,391 | 4.92 | 6,845 | 28,000 | 43,315 | 31.13 |
| Seabrook (Project 6) | 1,321 | 67.80 | 81,864 | 98.7 | 970 | 8.87 | 8,604 | 600 | 91,068 | 93.88 |
| | ======== | | ======== | | ======== | | ======== | ========= | ======= | ======= |
| SUBTOTAL - BASE | 3,521 | | 90,334 | | 2,361 | | 15,449 | 28,600 | 134,383 | 56.91 |
| Capacity Market Sales | -2,400 | 4.50 | -10,800 | | | | | | -10,800 | N/A |
| Capacity Market Purchases | 9,498 | 4.50 | 42,741 | | 0 | 0.00 | 0 | 0 | 42,741 | N/A |
| Dominion Capacity Purchase | 2,400 | 5.85 | 14,040 | | | | | | 14,040 | N/A |
| Energy Purchase | | | 0 | | 0 | 0.00 | 0 | | 0 | #DIV/0! |
| Miller Hydro Purchase | | | | | 151 | 63.50 | 9,561 | | 9,561 | 63.50 |
| Spruce Mtn Purchase | | | | | 176 | 99.25 | 17,446 | | 17,446 | 99.25 |
| Constellation "Bal Power" Purchase | | | 0 | | 1,947 | 59.90 | 116,607 | | 116,607 | 59.90 |
| | ======== | | ======== | | ======== | | ======== | ========= | ======= | ======= |
| SUBTOTAL - INTERMEDIATE | 11,898 | | 45,981 | | 2,273 | | 143,613 | 0 | 189,594 | 83.41 |
| NYPA Peak | 100 | 3.85 | 385 | 12.5 | 9 | 4.92 | 46 | 400 | 831 | 89.33 |
| | ======== | | ======== | | ======== | | ======== | ========= | ======= | ======= |
| SUBTOTAL - PEAKING | 100 | | 385 | | 9 | | 46 | 400 | 831 | 89.33 |
| ISO Energy Net Interchange | | | | | -147 | 37.89 | -5,575 | 0 | -5,575 | 37.89 |
| Service Billing | | | 100 | | 0 | 0.00 | 0 | 0 | 100 | 0.02 |
| Hydro Quebec I | 934 | 0 | | 0 | 0 | 0 | 0 | 1,500 | 1,500 | 0.33 |
| ENE All Req/Short Supply | | | 6,386 | | | 0.00 | 0 | 0 | 6,386 | 1.42 |
| ISO Annual Fee | | | | | | | | | 0 | 0.00 |
| ISO Load Based Charges | | | 2,616 | | | | | | 2,616 | 0.58 |
| ISO Scheduled Charges | | | 5,561 | | | | | | 5,561 | 1.24 |
| NEPOOL OATT Charge | | | 0 | | 0 | 0.00 | 0 | 61,425 | 61,425 | 13.66 |
| Network Transmission Service (NGRID) | | | 0 | | 0 | 0.00 | 0 | 20,000 | 20,000 | 4.45 |
| DAF (Subtransmission Ch) | | | 0 | | 0 | 0.00 | 0 | 6,600 | 6,600 | 1.47 |
| | ======== | | ======== | | ======== | | ======== | ========= | ======= | ======= |
| SUBTOTAL - OTHER CHARGE | 934 | | 14,662 | | 0 | | 0 | 89,525 | 104,188 | 23.17 |
| | ======== | | ======== | | ======== | | ======== | ========= | ======= | ======= |
| TOTAL | 3,434 | | 151,362 | | 4,497 //9A | | 153,534 | 118,525 | 423,421 //9A | 94.17 |

E=\$304,897 T=\$118,525 = \$423,422

Schedule G-4

# Bulk Powe st Projections
## Pascoag Utility District
## April-12

System Peak Demand (KW) 7,746
System Energy Requirements (MWH) 4,044

| RESOURCES | (KW) | FIXED COSTS Budget ($/KW-MO) | FIXED COSTS ($) | CF (%) | ENERGY VARIABLE COSTS MWH | Budget ($/MWH) | ($) | TRANS. COST Budget ($) | TOTAL COSTS Budget ($) | ($/MWH) |
|---|---|---|---|---|---|---|---|---|---|---|
| NYPA Firm | 2,200 | 3.85 | 8,470 | 85 | 1,346 | 4.92 | 6,624 | 20,600 | 35,694 | 26.51 |
| Seabrook (Project 6) | 1,321 | 67.80 | 81,864 | 98.7 | 939 | 8.87 | 8,327 | 600 | 90,791 | 96.71 |
| SUBTOTAL - BASE | 3,521 | | 90,334 | | 2,285 | | 14,951 | 21,200 | 126,485 | 55.35 |
| Capacity Market Sales | -2,400 | 4.50 | -10,800 | | | | | | -10,800 | N/A |
| Capacity Market Purchases | 9,498 | 4.50 | 42,741 | | 0 | 0.00 | 0 | 0 | 42,741 | N/A |
| Dominion Capacity Purchase | 2,400 | 5.85 | 14,040 | | | | | | 14,040 | N/A |
| Energy Purchase | | | 0 | | 0 | 0.00 | 0 | | 0 | #DIV/0! |
| Miller Hydro Purchase | | | | | 188 | 63.50 | 11,961 | | 11,961 | 63.50 |
| Spruce Mtn Purchase | | | | | 94 | 99.25 | 9,337 | | 9,337 | 99.25 |
| Constellation "Bal Power" Purchase | | | 0 | | 1,498 | 59.90 | 89,728 | | 89,728 | 59.90 |
| SUBTOTAL - INTERMEDIATE | 11,898 | | 45,981 | | 1,780 | | 111,026 | 0 | 157,007 | 88.19 |
| NYPA Peak | 100 | 3.85 | 385 | 12.5 | 9 | 4.92 | 44 | 400 | 829 | 92.14 |
| SUBTOTAL - PEAKING | 100 | | 385 | | 9 | | 44 | 400 | 829 | 92.14 |
| ISO Energy Net Interchange | | | | | -31 | 34.43 | -1,050 | 0 | -1,050 | 34.43 |
| Service Billing | | | 100 | | 0 | 0.00 | 0 | 0 | 100 | 0.02 |
| Hydro Quebec I | 934 | 0 | | 0 | 0 | 0 | 0 | 1,500 | 1,500 | 0.37 |
| ENE All Req/Short Supply | | | 6,386 | | | 0.00 | 0 | 0 | 6,386 | 1.58 |
| ISO Annual Fee | | | | | | | | | 0 | 0.00 |
| ISO Load Based Charges | | | 3,580 | | | | | | 3,580 | 0.89 |
| ISO Scheduled Charges | | | 5,887 | | | | | | 5,887 | 1.46 |
| NEPOOL OATT Charge | | | 0 | | 0 | 0.00 | 0 | 54,500 | 54,500 | 13.48 |
| Network Transmission Service (NGRID) | | | 0 | | 0 | 0.00 | 0 | 20,000 | 20,000 | 4.95 |
| DAF (Subtransmission Ch) | | | 0 | | 0 | 0.00 | 0 | 6,600 | 6,600 | 1.63 |
| SUBTOTAL - OTHER CHARGE | 934 | | 15,952 | | 0 | | 0 | 82,600 | 98,553 | 24.37 |
| TOTAL | 3,434 | | 152,652 | | 4,044 | | 124,971 | 104,200 | 381,823 | 94.42 |

E = $277,624    T=$104,200 = $381,824

Schedule G-5

# Bulk Powe st Projections
## Pascoag Utility District
## May-12

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| System Peak Demand (KW) | 8,901 | | | | | | | | | |
| System Energy Requirements (MWH) | 4,211 | | | | | | | | | |
| | | FIXED COSTS | | | | ENERGY VARIABLE COSTS | | TRANS. COST | TOTAL COSTS | |
| | | Budget | | CF | | Budget | | Budget | Budget | |
| RESOURCES | (KW) | ($/KW-MO) | ($) | (%) | MWH | ($/MWH) | ($) | ($) | ($) | ($/MWH) |
| NYPA Firm | 2,200 | 3.97 | 8,734 | 85 | 1,391 | 4.92 | 6,845 | 14,600 | 30,179 | 21.69 |
| Seabrook (Project 6) | 1,321 | 67.80 | 89,564 | 98.7 | 970 | 8.87 | 8,604 | 600 | 98,768 | 101.82 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - BASE | 3,521 | | 98,298 | | 2,361 ✓ | | 15,449 | 15,200 | 128,947 ✓ | 54.61 |
| Capacity Market Sales | -2,400 | 4.50 | -10,800 | | | | | | -10,800 | N/A |
| Capacity Market Purchases | 9,498 | 4.50 | 42,741 | | 0 | 0.00 | 0 | 0 | 42,741 | N/A |
| Dominion Capacity Purchase | 2,400 | 5.85 | 14,040 | | | | | | 14,040 | N/A |
| Energy Purchase | | | 0 | | 0 | 0.00 | 0 | | 0 | #DIV/0! |
| Miller Hydro Purchase | | | | | 181 | 63.50 | 11,468 | | 11,468 | 63.50 |
| Spruce Mtn Purchase | | | | | 127 | 99.25 | 12,629 | | 12,629 | 99.25 |
| Constellation "Bal Power" Purchase | | | 0 | | 1,654 | 59.90 | 99,099 | | 99,099 | 59.90 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - INTERMEDIATE | 11,898 | | 45,981 | | 1,962 ✓ | | 123,196 | 0 | 169,177 | 86.22 |
| NYPA Peak | 100 | 3.97 | 397 | 12.5 | 9 | 4.92 | 46 | 400 | 843 | 90.62 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - PEAKING | 100 | | 397 | | 9 | | 46 | 400 | 843 | 90.62 |
| ISO Energy Net Interchange | | | | | -122 | 33.98 | -4,151 | 0 | -4,151 | 33.98 |
| Service Billing | | | 100 | | 0 | 0.00 | 0 | 0 | 100 | 0.02 |
| Hydro Quebec I | 934 | 0 | | 0 | 0 | 0 | 0 | 1,500 | 1,500 | 0.36 |
| ENE All Req/Short Supply | | | 6,386 | | | 0.00 | 0 | 0 | 6,386 | 1.52 |
| ISO Annual Fee | | | | | | | | | 0 | 0.00 |
| ISO Load Based Charges | | | 2,411 | | | | | | 2,411 | 0.57 |
| ISO Scheduled Charges | | | 5,358 | | | | | | 5,358 | 1.27 |
| NEPOOL OATT Charge | | | 0 | | 0 | 0.00 | 0 | 48,211 | 48,211 | 11.45 |
| Network Transmission Service (NGRID) | | | 0 | | 0 | 0.00 | 0 | 20,000 | 20,000 | 4.75 |
| DAF (Subtransmission Ch) | | | 0 | | 0 | 0.00 | 0 | 6,600 | 6,600 | 1.57 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - OTHER CHARGE | 934 | | 14,255 | | 0 | | 0 | 76,311 | 90,566 | 21.51 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| TOTAL | 3,434 | | 158,931 | | 4,211 // ga | | 134,540 | 91,911 ✓ | 385,382 // ga | 91.52 |

E = $293,471 T = 91,911 = $385,382

Schedule G-6

**Bulk Powe st Projections**
**Pascoag Utility District**
**June-12**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| System Peak Demand (KW) | | 10,784 | | | | | | | | |
| System Energy Requirements (MWH) | | 4,556 | | | | | | | | |
| | | FIXED COSTS | | | ENERGY VARIABLE COSTS | | | TRANS. COST | TOTAL COSTS | |
| | | Budget | | CF | | Budget | | Budget | Budget | |
| RESOURCES | (KW) | ($/KW-MO) | ($) | (%) | MWH | ($/MWH) | ($) | ($) | ($) | ($/MWH) |
| NYPA Firm | 2,200 | 3.97 | 8,734 | 85 | 1,346 | 4.92 | 6,624 | 14,600 | 29,958 | 22.25 |
| Seabrook (Project 6) | 1,321 | 67.80 | 89,564 | 98.7 | 939 | 8.87 | 8,327 | 600 | 98,491 | 104.92 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - BASE | 3,521 | | 98,298 | | 2,285 | | 14,951 | 15,200 | 128,449 | 56.21 |
| Capacity Market Sales | -2,400 | 3.60 | -8,640 | | | | | | -8,640 | N/A |
| Capacity Market Purchases | 9,498 | 3.60 | 34,193 | | 0 | 0.00 | 0 | 0 | 34,193 | N/A |
| Dominion Capacity Purchase | 2,400 | 5.85 | 14,040 | | | | | | 14,040 | N/A |
| Energy Purchase | | | 0 | | 0 | 0.00 | 0 | | 0 | #DIV/0! |
| Miller Hydro Purchase | | | | | 145 | 63.50 | 9,195 | | 9,195 | 63.50 |
| Spruce Mtn Purchase | | | | | 149 | 99.25 | 14,774 | | 14,774 | 99.25 |
| Constellation "Bal Power" Purchase | | | 0 | | 2,362 | 59.90 | 141,482 | | 141,482 | 59.90 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - INTERMEDIATE | 11,898 | | 39,593 | | 2,656 | | 165,450 | 0 | 205,043 | 77.21 |
| NYPA Peak | 100 | 3.97 | 397 | 12.5 | 9 | 4.92 | 44 | 400 | 841 | 93.48 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - PEAKING | 100 | | 397 | | 9 | | 44 | 400 | 841 | 93.48 |
| ISO Energy Net Interchange | | | | | -394 | 34.07 | -13,410 | 0 | -13,410 | 34.07 |
| Service Billing | | | 100 | | 0 | 0.00 | 0 | 0 | 100 | 0.02 |
| Hydro Quebec I | 934 | 0 | | 0 | 0 | 0 | 0 | 1,500 | 1,500 | 0.33 |
| ENE All Req/Short Supply | | | 6,386 | | | 0.00 | 0 | 0 | 6,386 | 1.40 |
| ISO Annual Fee | | | | | | | | | 0 | 0.00 |
| ISO Load Based Charges | | | 2,505 | | | | | | 2,505 | 0.55 |
| ISO Scheduled Charges | | | 5,572 | | | | | | 5,572 | 1.22 |
| NEPOOL OATT Charge | | | 0 | | 0 | 0.00 | 0 | 55,404 | 55,404 | 12.16 |
| Network Transmission Service (NGRID) | | | 0 | | 0 | 0.00 | 0 | 20,000 | 20,000 | 4.39 |
| DAF (Subtransmission Ch) | | | 0 | | 0 | 0.00 | 0 | 6,600 | 6,600 | 1.45 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - OTHER CHARGE | 934 | | 14,563 | | 0 | | 0 | 83,504 | 98,067 | 21.52 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| TOTAL | 3,434 | | 152,850 | | 4,556 | | 167,035 | 99,104 | 418,990 | 91.96 |

E = $319,887 T = $99,104 = $418,991

Schedule G-7

# Bulk Powe st Projections
## Pascoag Utility District
## July-12

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| System Peak Demand (KW) | | 12,771 | | | | | | | | |
| System Energy Requirements (MWH) | | 5,433 | | | | | | | | |
| | | FIXED COSTS | | | ENERGY VARIABLE COSTS | | | TRANS. COST | TOTAL COSTS | |
| | | Budget | | CF | | Budget | | Budget | Budget | |
| RESOURCES | (KW) | ($/KW-MO) | ($) | (%) | MWH | ($/MWH) | ($) | ($) | ($) | ($/MWH) |
| NYPA Firm | 2,200 | 3.97 | 8,734 | 85 | 1,391 | 4.92 | 6,845 | 16,600 | 32,179 | 23.13 |
| Seabrook (Project 6) | 1,321 | 64.85 | 81,667 | 98.7 | 970 | 9.59 | 9,301 | 600 | 91,568 | 94.40 |
| SUBTOTAL - BASE | 3,521 | | 90,401 | | 2,361 | | 16,146 | 17,200 | 123,747 | 52.41 |
| Capacity Market Sales | -2,400 | 3.60 | -8,640 | | | | | | -8,640 | N/A |
| Capacity Market Purchases | 9,498 | 3.60 | 34,193 | | 0 | 0.00 | 0 | 0 | 34,193 | N/A |
| Dominion Capacity Purchase | 2,400 | 5.85 | 14,040 | | | | | | 14,040 | N/A |
| Energy Purchase | | | 0 | | 0 | 0.00 | 0 | | 0 | #DIV/0! |
| Miller Hydro Purchase | | | | | 95 | 63.50 | 6,031 | | 6,031 | 63.50 |
| Spruce Mtn Purchase | | | | | 93 | 99.25 | 9,210 | | 9,210 | 99.25 |
| Constellation "Bal Power" Purchase | | | 0 | | 3,400 | 59.90 | 203,665 | | 203,665 | 59.90 |
| SUBTOTAL - INTERMEDIATE | 11,898 | | 39,593 | | 3,588 | | 218,905 | 0 | 258,498 | 72.05 |
| NYPA Peak | 100 | 3.97 | 397 | 12.5 | 9 | 4.92 | 46 | 400 | 843 | 90.62 |
| SUBTOTAL - PEAKING | 100 | | 397 | | 9 | | 46 | 400 | 843 | 90.62 |
| ISO Energy Net Interchange | | | | | -526 | 36.90 | -19,398 | 0 | -19,398 | 36.90 |
| Service Billing | | | 100 | | 0 | 0.00 | 0 | 0 | 100 | 0.02 |
| Hydro Quebec I | 934 | 0 | | 0 | 0 | 0 | 0 | 1,500 | 1,500 | 0.28 |
| ENE All Req/Short Supply | | | 6,386 | | | 0.00 | 0 | 0 | 6,386 | 1.18 |
| ISO Annual Fee | | | | | | | | | 0 | 0.00 |
| ISO Load Based Charges | | | 3,532 | | | | | | 3,532 | 0.65 |
| ISO Scheduled Charges | | | 5,755 | | | | | | 5,755 | 1.06 |
| NEPOOL OATT Charge | | | 0 | | 0 | 0.00 | 0 | 67,122 | 67,122 | 12.35 |
| Network Transmission Service (NGRID) | | | 0 | | 0 | 0.00 | 0 | 20,000 | 20,000 | 3.68 |
| DAF (Subtransmission Ch) | | | 0 | | 0 | 0.00 | 0 | 6,600 | 6,600 | 1.21 |
| SUBTOTAL - OTHER CHARGE | 934 | | 15,772 | | 0 | | 0 | 95,222 | 110,994 | 20.43 |
| TOTAL | 3,434 | | 146,163 | | 5,433 | | 215,700 | 112,822 | 474,684 | 87.37 |

E = \$361,864 T = \$112,822 = \$474,686

Schedule G-8

# Bulk Powe st Projections
## Pascoag Utility District
## August-12

System Peak Demand (KW) 11,015
System Energy Requirements (MWH) 5,211

| RESOURCES | FIXED COSTS (KW) | FIXED COSTS Budget ($/KW-MO) | FIXED COSTS ($) | CF (%) | ENERGY VARIABLE COSTS MWH | ENERGY VARIABLE COSTS Budget ($/MWH) | ENERGY VARIABLE COSTS ($) | TRANS. COST Budget ($) | TOTAL COSTS Budget ($) | TOTAL COSTS ($/MWH) |
|---|---|---|---|---|---|---|---|---|---|---|
| NYPA Firm | 2,200 | 3.97 | 8,734 | 85 | 1,391 | 4.92 | 6,845 | 18,600 | 34,179 | 24.57 |
| Seabrook (Project 6) | 1,321 | 64.85 | 81,667 | 98.7 | 970 | 9.59 | 9,301 | 600 | 91,568 | 94.40 |
| SUBTOTAL - BASE | 3,521 | | 90,401 | | 2,361 | | 16,146 | 19,200 | 125,747 | 53.25 |
| Capacity Market Sales | -2,400 | 3.60 | -8,640 | | | | | | -8,640 | N/A |
| Capacity Market Purchases | 9,498 | 3.60 | 34,193 | | 0 | 0.00 | 0 | 0 | 34,193 | N/A |
| Dominion Capacity Purchase | 2,400 | 5.85 | 14,040 | | | | | | 14,040 | N/A |
| Energy Purchase | | | 0 | | 0 | 0.00 | 0 | | 0 | #DIV/0! |
| Miller Hydro Purchase | | | | | 84 | 63.50 | 5,352 | | 5,352 | 63.50 |
| Spruce Mtn Purchase | | | | | 97 | 99.25 | 9,612 | | 9,612 | 99.25 |
| Constellation "Bal Power" Purchase | | | 0 | | 2,754 | 59.90 | 164,992 | | 164,992 | 59.90 |
| SUBTOTAL - INTERMEDIATE | 11,898 | | 39,593 | | 2,936 | | 179,956 | 0 | 219,549 | 74.79 |
| NYPA Peak | 100 | 3.97 | 397 | 12.5 | 9 | 4.92 | 46 | 400 | 843 | 90.62 |
| SUBTOTAL - PEAKING | 100 | | 397 | | 9 | | 46 | 400 | 843 | 90.62 |
| ISO Energy Net Interchange | | | | | -96 | 36.90 | -3,528 | 0 | -3,528 | 36.90 |
| Service Billing | | | 100 | | 0 | 0.00 | 0 | 0 | 100 | 0.02 |
| Hydro Quebec I | 934 | 0 | | 0 | 0 | 0 | 0 | 1,500 | 1,500 | 0.29 |
| ENE All Req/Short Supply | | | 6,386 | | | 0.00 | 0 | 0 | 6,386 | 1.23 |
| ISO Annual Fee | | | | | | | | | 0 | 0.00 |
| ISO Load Based Charges | | | 10,578 | | | | | | 10,578 | 2.03 |
| ISO Scheduled Charges | | | 9,197 | | | | | | 9,197 | 1.76 |
| NEPOOL OATT Charge | | | 0 | | 0 | 0.00 | 0 | 88,942 | 88,942 | 17.07 |
| Network Transmission Service (NGRID) | | | 0 | | 0 | 0.00 | 0 | 20,000 | 20,000 | 3.84 |
| DAF (Subtransmission Ch) | | | 0 | | 0 | 0.00 | 0 | 6,600 | 6,600 | 1.27 |
| SUBTOTAL - OTHER CHARGE | 934 | | 26,260 | | 0 | | 0 | 117,042 | 143,302 | 27.50 |
| TOTAL | 3,434 | | 156,651 | | 5,211 | | 192,619 | 136,642 | 485,913 | 93.25 |

E = $349,272 T= $136,642 = $485,914

Schedule G-9

**Bulk Power st Projections**
**Pascoag Utility District**
**September-12**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| System Peak Demand (KW) | | 11,629 | | | | | | | | |
| System Energy Requirements (MWH) | | 4,387 | | | | | | | | |
| | | FIXED COSTS | | | ENERGY VARIABLE COSTS | | | TRANS. COST | TOTAL COSTS | |
| | | Budget | | CF | | Budget | | Budget | Budget | |
| RESOURCES | (KW) | ($/KW-MO) | ($) | (%) | MWH | ($/MWH) | ($) | ($) | ($) | ($/MWH) |
| NYPA Firm | 2,200 | 3.97 | 8,734 | 85 | 1,346 | 4.92 | 6,624 | 15,600 | 30,958 | 22.99 |
| Seabrook (Project 6) | 1,321 | 64.85 | 81,667 | 98.7 | 939 | 9.59 | 9,001 | 600 | 91,268 | 97.22 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - BASE | 3,521 | | 90,401 | | 2,285 ✓ | | 15,626 | 16,200 | 122,226 ✓ | 53.49 |
| Capacity Market Sales | -2,400 | 3.60 | -8,640 | | | | | | -8,640 | N/A |
| Capacity Market Purchases | 9,498 | 3.60 | 34,193 | | 0 | 0.00 | 0 | 0 | 34,193 | N/A |
| Dominion Capacity Purchase | 2,400 | 5.85 | 14,040 | | | | | | 14,040 | N/A |
| Energy Purchase | | | 0 | | 0 | 0.00 | 0 | | 0 | #DIV/0! |
| Miller Hydro Purchase | | | | | 68 | 63.50 | 4,314 | | 4,314 | 63.50 |
| Spruce Mtn Purchase | | | | | 125 | 99.25 | 12,391 | | 12,391 | 99.25 |
| Constellation "Bal Power" Purchase | | | 0 | | 2,107 | 59.90 | 126,209 | | 126,209 | 59.90 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - INTERMEDIATE | 11,898 | | 39,593 | | 2,300 ✓ | | 142,914 | 0 | 182,507 | 79.36 |
| NYPA Peak | 100 | 3.97 | 397 | 12.5 | 9 | 4.92 | 44 | 400 | 841 | 93.48 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - PEAKING | 100 | | 397 | | 9 | | 44 | 400 | 841 | 93.48 |
| ISO Energy Net Interchange | | | | | -206 | 33.53 | -6,923 | 0 | -6,923 | 33.53 |
| Service Billing | | | 100 | | 0 | 0.00 | 0 | 0 | 100 | 0.02 |
| Hydro Quebec I | 934 | 0 | | 0 | 0 | 0 | 0 | 1,500 | 1,500 | 0.34 |
| ENE All Req/Short Supply | | | 6,386 | | | 0.00 | 0 | 0 | 6,386 | 1.46 |
| ISO Annual Fee | | | | | | | | | 0 | 0.00 |
| ISO Load Based Charges | | | 8,099 | | | | | | 8,099 | 1.85 |
| ISO Scheduled Charges | | | 7,884 | | | | | | 7,884 | 1.80 |
| NEPOOL OATT Charge | | | 0 | | 0 | 0.00 | 0 | 76,708 | 76,708 | 17.48 |
| Network Transmission Service (NGRID) | | | 0 | | 0 | 0.00 | 0 | 20,000 | 20,000 | 4.56 |
| DAF (Subtransmission Ch) | | | 0 | | 0 | 0.00 | 0 | 6,600 | 6,600 | 1.50 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - OTHER CHARGE | 934 | | 22,469 | | 0 | | 0 | 104,808 | 127,277 | 29.01 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| TOTAL | 3,434 | | 152,859 | | 4,387 | | 151,661 | 121,408 ✓ | 425,929 | 97.08 |

E = $304,520 T = $121,408 = $425,928

Schedule G-10

# Bulk Power[illegible]st Projections
## Pascoag Utility District
## October-12

| | |
|---|---|
| System Peak Demand (KW) | 8,189 |
| System Energy Requirements (MWH) | 4,321 |

| RESOURCES | (KW) | FIXED COSTS Budget ($/KW-MO) | FIXED COSTS ($) | CF (%) | ENERGY VARIABLE COSTS MWH | ENERGY VARIABLE COSTS Budget ($/MWH) | ENERGY VARIABLE COSTS ($) | TRANS. COST Budget ($) | TOTAL COSTS Budget ($) | TOTAL COSTS ($/MWH) |
|---|---|---|---|---|---|---|---|---|---|---|
| NYPA Firm | 2,200 | 3.97 | 8,734 | 85 | 1,391 | 4.92 | 6,845 | 20,600 | 36,179 | 26.00 |
| Seabrook (Project 6) | 1,321 | 64.85 | 81,667 | 0 | 0 | 9.59 | 0 | 600 | 82,267 | #DIV/0! |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - BASE | 3,521 | | 90,401 | | 1,391 | | 6,845 | 21,200 | 118,446 | 85.13 |
| Capacity Market Sales | -2,400 | 3.60 | -8,640 | | | | | | -8,640 | N/A |
| Capacity Market Purchases | 9,498 | 3.60 | 34,193 | | 0 | 0.00 | 0 | 0 | 34,193 | N/A |
| Dominion Capacity Purchase | 2,400 | 5.85 | 14,040 | | | | | | 14,040 | N/A |
| Energy Purchase | | | 0 | | 0 | 0.00 | 0 | | 0 | #DIV/0! |
| Miller Hydro Purchase | | | | | 104 | 63.50 | 6,629 | | 6,629 | 63.50 |
| Spruce Mtn Purchase | | | | | 154 | 99.25 | 15,273 | | 15,273 | 99.25 |
| Constellation "Bal Power" Purchase | | | 0 | | 1,730 | 59.90 | 103,619 | | 103,619 | 59.90 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - INTERMEDIATE | 11,898 | | 39,593 | | 1,988 | | 125,521 | 0 | 165,114 | 83.05 |
| NYPA Peak | 100 | 3.97 | 397 | 12.5 | 9 | 4.92 | 46 | 400 | 843 | 90.62 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - PEAKING | 100 | | 397 | | 9 | | 46 | 400 | 843 | 90.62 |
| ISO Energy Net Interchange | | | | | 932 | 35.43 | 33,024 | 0 | 33,024 | 35.43 |
| Service Billing | | | 100 | | 0 | 0.00 | 0 | 0 | 100 | 0.02 |
| Hydro Quebec I | 934 | 0 | | 0 | 0 | 0 | 0 | 1,500 | 1,500 | 0.35 |
| ENE All Req/Short Supply | | | 6,386 | | | 0.00 | 0 | 0 | 6,386 | 1.48 |
| ISO Annual Fee | | | | | | | | | 0 | 0.00 |
| ISO Load Based Charges | | | 2,152 | | | | | | 2,152 | 0.50 |
| ISO Scheduled Charges | | | 7,952 | | | | | | 7,952 | 1.84 |
| NEPOOL OATT Charge | | | 0 | | 0 | 0.00 | 0 | 80,986 | 80,986 | 18.74 |
| Network Transmission Service (NGRID) | | | 0 | | 0 | 0.00 | 0 | 20,000 | 20,000 | 4.63 |
| DAF (Subtransmission Ch) | | | 0 | | 0 | 0.00 | 0 | 7,400 | 7,400 | 1.71 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - OTHER CHARGE | 934 | | 16,590 | | 0 | | 0 | 109,886 | 126,476 | 29.27 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| TOTAL | 3,434 | | 146,981 | | 4,321 94 | | 165,437 | 131,486 94 | 443,903 94 | 102.74 |

Pascoag Fuel Reconciliation 2012.xlsm E = $312,417 Oct 12 T = $131,486 = $443,903 10/14/2011

Schedule G-11

# Bulk Powe st Projections
## Pascoag Utility District
## November-12

System Peak Demand (KW) 9,126
System Energy Requirements (MWH) 4,395

| RESOURCES | (KW) | FIXED COSTS Budget ($/KW-MO) | FIXED COSTS ($) | CF (%) | ENERGY VARIABLE COSTS MWH | ENERGY VARIABLE COSTS Budget ($/MWH) | ENERGY VARIABLE COSTS ($) | TRANS. COST Budget ($) | TOTAL COSTS Budget ($) | TOTAL COSTS ($/MWH) |
|---|---|---|---|---|---|---|---|---|---|---|
| NYPA Firm | 2,200 | 3.97 | 8,734 | 85 | 1,346 | 4.92 | 6,624 | 20,600 | 35,958 | 26.71 |
| Seabrook (Project 6) | 1,321 | 64.85 | 81,667 | 98.7 | 939 | 9.59 | 9,001 | 600 | 91,268 | 97.22 |
| SUBTOTAL - BASE | 3,521 | | 90,401 | | 2,285 | | 15,626 | 21,200 | 127,226 | 55.68 |
| Capacity Market Sales | -2,400 | 3.60 | -8,640 | | | | | | -8,640 | N/A |
| Capacity Market Purchases | 9,498 | 3.60 | 34,193 | | 0 | 0.00 | 0 | 0 | 34,193 | N/A |
| Dominion Capacity Purchase | 2,400 | 5.85 | 14,040 | | | | | | 14,040 | N/A |
| Energy Purchase | | | 0 | | 0 | 0.00 | 0 | | 0 | #DIV/0! |
| Miller Hydro Purchase | | | | | 137 | 63.50 | 8,693 | | 8,693 | 63.50 |
| Spruce Mtn Purchase | | | | | 160 | 99.25 | 15,854 | | 15,854 | 99.25 |
| Constellation "Bal Power" Purchase | | | 0 | | 1,876 | 59.90 | 112,365 | | 112,365 | 59.90 |
| SUBTOTAL - INTERMEDIATE | 11,898 | | 39,593 | | 2,173 | | 136,912 | 0 | 176,505 | 81.24 |
| NYPA Peak | 100 | 3.97 | 397 | 12.5 | 9 | 4.92 | 44 | 400 | 841 | 93.48 |
| SUBTOTAL - PEAKING | 100 | | 397 | | 9 | | 44 | 400 | 841 | 93.48 |
| ISO Energy Net Interchange | | | | | -72 | 37.76 | -2,725 | 0 | -2,725 | 37.76 |
| Service Billing | | | 100 | | 0 | 0.00 | 0 | 0 | 100 | 0.02 |
| Hydro Quebec I | 934 | 0 | | 0 | 0 | 0 | 0 | 1,500 | 1,500 | 0.34 |
| ENE All Req/Short Supply | | | 6,386 | | | 0.00 | 0 | 0 | 6,386 | 1.45 |
| ISO Annual Fee | | | | | | | | | 0 | 0.00 |
| ISO Load Based Charges | | | 1,876 | | | | | | 1,876 | 0.43 |
| ISO Scheduled Charges | | | 6,030 | | | | | | 6,030 | 1.37 |
| NEPOOL OATT Charge | | | 0 | | 0 | 0.00 | 0 | 57,027 | 57,027 | 12.98 |
| Network Transmission Service (NGRID) | | | 0 | | 0 | 0.00 | 0 | 20,000 | 20,000 | 4.55 |
| DAF (Subtransmission Ch) | | | 0 | | 0 | 0.00 | 0 | 7,400 | 7,400 | 1.68 |
| SUBTOTAL - OTHER CHARGE | 934 | | 14,392 | | 0 | | 0 | 85,927 | 100,319 | 22.83 |
| TOTAL | 3,434 | | 144,783 | | 4,395 | | 149,857 | 107,527 | 402,167 | 91.52 |

E= $294,639 T=$107,527 = $402,166

Schedule G-12

# Bulk Power st Projections
## Pascoag Utility District
## December-12

System Peak Demand (KW) 10,146
System Energy Requirements (MWH) 5,029

| RESOURCES | (KW) | FIXED COSTS Budget ($/KW-MO) | FIXED COSTS ($) | CF (%) | ENERGY VARIABLE COSTS MWH | Budget ($/MWH) | ($) | TRANS. COST Budget ($) | TOTAL COSTS Budget ($) | ($/MWH) |
|---|---|---|---|---|---|---|---|---|---|---|
| NYPA Firm | 2,200 | 3.97 | 8,734 | 85 | 1,391 | 4.92 | 6,845 | 18,600 | 34,179 | 24.57 |
| Seabrook (Project 6) | 1,321 | 64.85 | 81,667 | 98.7 | 970 | 9.59 | 9,301 | 600 | 91,568 | 94.40 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - BASE | 3,521 | | 90,401 | | 2,361 | | 16,146 | 19,200 | 125,747 | 53.25 |
| Capacity Market Sales | -2,400 | 3.60 | -8,640 | | | | | | -8,640 | N/A |
| Capacity Market Purchases | 9,498 | 3.60 | 34,193 | | 0 | 0.00 | 0 | 0 | 34,193 | N/A |
| Dominion Capacity Purchase | 2,400 | 5.85 | 14,040 | | | | | | 14,040 | N/A |
| Energy Purchase | | | 0 | | 0 | 0.00 | 0 | | 0 | #DIV/0! |
| Miller Hydro Purchase | | | | | 137 | 63.50 | 8,730 | | 8,730 | 63.50 |
| Spruce Mtn Purchase | | | | | 186 | 99.25 | 18,442 | | 18,442 | 99.25 |
| Constellation "Bal Power" Purchase | | | 0 | | 2,426 | 59.90 | 145,347 | | 145,347 | 59.90 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - INTERMEDIATE | 11,898 | | 39,593 | | 2,750 | | 172,519 | 0 | 212,112 | 77.14 |
| NYPA Peak | 100 | 3.97 | 397 | 12.5 | 9 | 4.92 | 46 | 400 | 843 | 90.62 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - PEAKING | 100 | | 397 | | 9 | | 46 | 400 | 843 | 90.62 |
| ISO Energy Net Interchange | | | | | -92 | 45.70 | -4,188 | 0 | -4,188 | 45.70 |
| Service Billing | | | 100 | | 0 | 0.00 | 0 | 0 | 100 | 0.02 |
| Hydro Quebec I | 934 | 0 | | 0 | 0 | 0 | 0 | 1,500 | 1,500 | 0.30 |
| ENE All Req/Short Supply | | | 6,386 | | | 0.00 | 0 | 0 | 6,386 | 1.27 |
| ISO Annual Fee | | | | | | | | | 0 | 0.00 |
| ISO Load Based Charges | | | 3,062 | | | | | | 3,062 | 0.61 |
| ISO Scheduled Charges | | | 6,389 | | | | | | 6,389 | 1.27 |
| NEPOOL OATT Charge | | | 0 | | 0 | 0.00 | 0 | 63,555 | 63,555 | 12.64 |
| Network Transmission Service (NGRID) | | | 0 | | 0 | 0.00 | 0 | 20,000 | 20,000 | 3.98 |
| DAF (Subtransmission Ch) | | | 0 | | 0 | 0.00 | 0 | 7,400 | 7,400 | 1.47 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| SUBTOTAL - OTHER CHARGE | 934 | | 15,936 | | 0 | | 0 | 92,455 | 108,391 | 21.55 |
| | ======== | | ======== | | ======== | | ======== | ======== | ======= | ======= |
| TOTAL | 3,434 | | 146,327 | | 5,029 | | 184,523 | 112,055 | 442,905 | 88.07 |

E = $ 330,851 T= $ 112,055 $442,906

Schedule G-13

# Bulk Power Cost Projections
## Pascoag Utility District
## January 2012 through December 2012 - FINAL

System Peak Demand (KW) 11,015
System Energy Requirements (MWH) 55,449

| RESOURCES | (KW) | FIXED COSTS Budget ($/KW-MO) | FIXED COSTS ($) | CF (%) | ENERGY VARIABLE COSTS MWH | ENERGY VARIABLE COSTS Budget ($/MWH) | ENERGY VARIABLE COSTS ($) | TRANS. COSTS Budget ($) | TOTAL COSTS Budget ($) | TOTAL COSTS Budget ($/MWH) |
|---|---|---|---|---|---|---|---|---|---|---|
| NYPA Firm | 2,200 | 3.93 | 103,752 | 85 | 16,426 | 4.92 | 80,816 | 254,400 | 438,968 | 26.72 |
| Seabrook (Project 6) | 1,321 | 62.87 | 996,584 | 90 | 10,483 | 9.20 | 96,422 | 7,200 | 1,100,206 | 104.95 |
| SUBTOTAL - BASE | 3,521 | | 1,100,336 | | 26,909 | | 177,238 | 261,600 | 1,539,174 | 131.68 |
| Capacity Market Sales | -4,374 | | -114,480 | | 0 | | 0 | 0 | -114,480 | NA |
| Capacity Market Purchases | 14,541 | | 453,055 | | 0 | | 0 | 0 | 453,055 | NA |
| Dominion Capacity Purchase | 2,400 | | 168,480 | | 0 | | 0 | 0 | 168,480 | NA |
| Energy Purchase | | | 0 | | 0 | #DIV/0! | 0 | 0 | 0 | #DIV/0! |
| Miller Hydro Purchase | | | 0 | | 1,531 | 63.50 | 97,238 | 0 | 97,238 | 63.50 |
| Spruce Mtn Purchase | | | | | 1,730 | 99.25 | 171,736 | 0 | 171,736 | 99.25 |
| Constellation "Bal Power" Purchase | | | 0 | | 26,338 | 59.90 | 1,577,631 | 0 | 1,577,631 | 59.90 |
| SUBTOTAL - INTERMEDIATE | 2,400 | | 507,055 | | 29,599 | | 1,846,606 | 0 | 2,353,660 | 79.52 |
| NYPA Peak | 100 | 3.93 | 4,716 | 13 | 110 | 4.92 | 540 | 4,800 | 10,056 | 91.59 |
| SUBTOTAL - PEAKING | 100 | | 4,716 | | 110 | | 540 | 4,800 | 10,056 | 91.59 |
| ISO Energy Net Interchange | | | | | -1,169 | 42.99 | -50,258 | 0 | -50,258 | -0.91 |
| Service Billing | | | 1,200 | | 0 | | 0 | 0 | 1,200 | 0.02 |
| Hydro Quebec I | 934 | | 0 | | 0 | | 0 | 18,000 | 18,000 | 0.32 |
| ENE All Req/Short Supply | | | 76,632 | | 0 | | 0 | 0 | 76,632 | 1.38 |
| ISO Annual Fee | | | 5,360 | | 0 | | 0 | 0 | 5,360 | 0.10 |
| ISO Load Based Charges | | | 48,709 | | 0 | | 0 | 0 | 48,709 | 0.88 |
| ISO Scheduled Charges | | | 73,248 | | 0 | | 0 | 0 | 73,248 | 1.32 |
| NEPOOL OATT Charge | | | 0 | | 0 | | 0 | 778,585 | 778,585 | 14.04 |
| Network Transmission Service (NGRID) | | | 0 | | 0 | | 0 | 240,000 | 240,000 | 4.33 |
| DAF (Subtransmission Ch) | | | 0 | | 0 | | 0 | 81,600 | 81,600 | 1.47 |
| SUBTOTAL - OTHER CHARGE | 934 | | 205,149 | | 0 | | 0 | 1,118,185 | 1,323,334 | 23.87 |
| TOTAL | 6,955 | | 1,817,255 | | 55,449 ✓ | 35.60 | 1,974,126 | 1,384,585 | 5,175,967 | 93.35 |

T= $1,384,584 E= $3,791,387 = $5,175,971

| | A | B | F | G | H |
|---|---|---|---|---|---|
| 1 | | | | | **Schedule H** |
| 2 | | | | | **Option 1 - Flow Back $200,000** |
| 3 | | | **Forecast Rates** | | |
| 4 | | | | | |
| 5 | **Transition Cost Calculations:** | | | | |
| 6 | Estimated Sales (MWH) to customers | | 52,318 | | See Schedule F-2, Line 106 |
| 7 | | | | | |
| 8 | Forecast Transition Cost | | $603,000 | | See Schedule F-2, line 97 |
| 9 | Historic Transistion Revenue | | ($603,614) | | See Schedule A-3, Line 138 |
| 10 | Historic Transition Expense | | $606,000 | | See Schedule A-2, Line 75 |
| 11 | Carry over from prior period (12/31/2010) | | ($25,369) | | See Schedule C-3, Line 73 |
| 12 | | Total | $580,017 | | |
| 13 | | | | | |
| 14 | **Cost Per MWH** | | **$ 11.09** | | |
| 15 | | | | | |
| 16 | **Transmission Cost Calculations:** | | | | |
| 17 | Estimated Sales (MWH) to customers | | 52,318 | | See Schedule F-2, Line 106 |
| 18 | | | | | |
| 19 | Forecast Transmission Cost | | $1,384,584 | | See Schedule F-2, line 98 |
| 20 | Historic Transmission Revenue | | ($1,208,525) | | See Schedule A-3, Line 140 |
| 21 | Historic Transmission Expense | | $1,226,648 | | See Schedule A-2, Line 80 |
| 22 | Carry over from prior period (12/31/2010) | | ($136,707) | | See Schedule C-4, Line 85 |
| 23 | | Total | $1,266,000 | | |
| 24 | | | | | |
| 25 | **Cost per MWH** | | **$ 24.20** | | |
| 26 | | | | | |
| 27 | **Standard Offer Calculation:** | | | | |
| 28 | Estimated Sales (MWH) to customers | | 52,318 | | See Schedule F-2, Line 106 |
| 29 | | | | | |
| 30 | Forecast Standard Offer | | $3,188,387 | | See Schedule F-2, line 99 |
| 31 | Historic SOS Revenue | | ($3,783,710) | | See Schedule A-3, Line 139 |
| 32 | Historic SOS Expense | | $3,621,368 | | See Schedule A-2, Line 97 |
| 33 | Flow Back of $200,000 from 2010 filing | | ($200,000) | | Retained for L'Energia or RSF |
| 34 | Carry over from prior period (12/31/2010) | | ($89,093) | | See Schedule C-2, Line 82 |
| 35 | | Total | $2,736,952 | | |
| 36 | | | | | |
| 37 | **Cost per MWH** | | **$ 52.31** | | |
| 38 | | | | | **$ 87.60** |
| 39 | | | | | |
| 40 | | | | | |
| 41 | | | **Revenue/Expense Proof:** | | |
| 42 | | | | | |
| 43 | Forecast Transition Cost | | $ 603,000 | | See Schedule F-2, line 97 |
| 44 | Over/Under Collection at period end | | $ (22,983) | | Schedule C-3, Line 99 |
| 45 | | | $ 580,017 | | $ 11.09 |
| 46 | | | | | |
| 47 | Forecast Transmission Cost | | $ 1,384,584 | | See Schedule F-2, line 98 |
| 48 | Over/Under Collection at period end | | $ (118,584) | | Schedule C-4, Line 109 |
| 49 | | | $ 1,266,000 | | $ 24.20 |
| 50 | | | | | |
| 51 | Forecast SOS Cost | | $ 3,188,387 | | See Schedule F-2, line 99 |
| 52 | Flow Back of $200,000 from 2010 filing | | ($200,000) | | Retained for L'Energia or RSF |
| 53 | Over/Under Collection at period end | | ($251,435) | | Schedule C-2, Line 109 |
| 54 | | | $ 2,736,952 | | $ 52.31 |
| 55 | | | | | |
| 56 | | | | | **$ 87.60** |
| 57 | | | | | |
| 58 | | | | | |
| 59 | | | | | |

| | A | B | F | G | H |
|---|---|---|---|---|---|
| 60 | | | | | |
| 61 | | | | | **Schedule H** |
| 62 | | | | | **Option 2 - PUD retains $200,000** |
| 63 | | | **Forecast Rates** | | |
| 64 | | | **(With Retaintion of $200,000 for Rate Stabilization Fund)** | | |
| 65 | | | | | |
| 66 | **Transition Cost Calculations:** | | | | |
| 67 | Estimated Sales (MWH) to customers | | 52,318 | | See Schedule F-2, Line 106 |
| 68 | | | | | |
| 69 | Forecast Transition Cost | | $603,000 | | See Schedule F-2, line 97 |
| 70 | Historic Transistion Revenue | | ($603,614) | | See Schedule A-3, Line 138 |
| 71 | Historic Transition Expense | | $606,000 | | See Schedule A-2, Line 75 |
| 72 | Carry over from prior period (12/31/2009) | | ($25,369) | | See Schedule C-3, Line 73 |
| 73 | | Total | $580,017 | | |
| 74 | | | | | |
| 75 | **Cost Per MWH** | | **$ 11.09** | | |
| 76 | | | | | |
| 77 | **Transmission Cost Calculations:** | | | | |
| 78 | Estimated Sales (MWH) to customers | | 52,318 | | See Schedule F-2, Line 106 |
| 79 | | | | | |
| 80 | Forecast Transmission Cost | | $1,384,584 | | See Schedule F-2, line 98 |
| 81 | Historic Transmission Revenue | | ($1,208,525) | | See Schedule A-3, Line 140 |
| 82 | Historic Transmission Expense | | $1,226,648 | | See Schedule A-2, Line 80 |
| 83 | Carry over from prior period (12/31/2009) | | ($136,707) | | See Schedule C-4, Line 85 |
| 84 | | Total | $1,266,000 | | |
| 85 | | | | | |
| 86 | **Cost per MWH** | | **$ 24.20** | | |
| 87 | | | | | |
| 88 | **Standard Offer Calculation:** | | | | |
| 89 | Estimated Sales (MWH) to customers | | 52,318 | | See Schedule F-2, Line 106 |
| 90 | | | | | |
| 91 | Forecast Standard Offer | | $3,188,387 | | See Schedule F-2, line 99 |
| 92 | Historic SOS Revenue | | ($3,783,710) | | See Schedule A-3, Line 139 |
| 93 | Historic SOS Expense | | $3,621,368 | | See Schedule A-2, Line 97 |
| 94 | Carry over from prior period (12/31/2009) | | ($89,093) | | See Schedule C-2, Line 82 |
| 95 | | Total | $2,936,952 | | |
| 96 | | | | | |
| 97 | **Cost per MWH** | | **$ 56.14** | | |
| 98 | | | | | **$ 91.42** |
| 99 | | | **Revenue/Expense Proof:** | | |
| 100 | | | | | |
| 101 | Forecast Transition Cost | | $ 603,000 | | See Schedule F-2, line 97 |
| 102 | Over/Under Collection at period end | | $ (22,983) | | Schedule C-3, Line 99 |
| 103 | | | $ 580,017 | | $ 11.09 |
| 104 | | | | | |
| 105 | Forecast Transmission Cost | | $ 1,384,584 | | See Schedule F-2, line 98 |
| 106 | Over/Under Collection at period end | | $ (118,584) | | Schedule C-4, Line 109 |
| 107 | | | $ 1,266,000 | | $ 24.20 |
| 108 | | | | | |
| 109 | Forecast SOS Cost | | $ 3,188,387 | | See Schedule F-2, line 99 |
| 110 | Over/Under Collection at period end | | ($251,435) | | Schedule C-2, Line 109 |
| 111 | | | | | |
| 112 | | | $ 2,936,952 | | $ 56.14 |
| 113 | | | | | **$ 91.42** |

## Pascoag Utility District - Electric Department
### Comparison of Previous Rate vs Proposed Rate
### Option 1 - Pascoag Flows Back $200,000

| Current Rate | Unit Cost | Total | Rate Adjusted w/Actual thru Period End | Unit Cost | Total | |
|---|---|---|---|---|---|---|
| Customer Charge | | $ 4.00 | Customer Charge | | $ 4.00 | |
| Distribution | $ 0.03464 | $ 17.32 | Distribution | $ 0.03464 | $ 17.32 | |
| Transition | $ 0.01132 | $ 5.65 | Transition | $ 0.01109 | $ 5.54 | See Schedule H, Line 14 |
| Standard Offer | $ 0.07064 | $ 35.32 | Standard Offer | $ 0.05231 | $ 26.16 | See Schedule H, Line 37 |
| Transmission | $ 0.02290 | $ 11.46 | Transmission | $ 0.02420 | $ 12.10 | See Schedule H, Line 25 |
| DSM/Renewable | $ 0.00230 | $ 1.15 | DSM | $ 0.00230 | $ 1.15 | |
| Total | | $ 74.90 | Total | | $ 66.27 | |
| | **Net Increase/(Decrease)** | | | | **$ (8.63)** | |
| | **Percent Increase/(Decrease)** | | | | **-11.5%** | |

Schedule H-1

OPTION 1

Schedule H-1

OPTION 2

## Pascoag Utility District - Electric Department

**Comparison of Previous Rate vs Proposed Rate**

**Option 2 - PUD Retains $200,000**

| Current Rate | Unit Cost | Total | Rate Adjusted w/Actual thru Period End | Unit Cost | Total | |
|---|---|---|---|---|---|---|
| Customer Charge | | $ 4.00 | Customer Charge | | $ 4.00 | |
| Distribution | $ 0.03464 | $ 17.32 | Distribution | $ 0.03464 | $ 17.32 | |
| Transition | $ 0.01132 | $ 5.65 | Transition | $ 0.01109 | $ 5.54 | See Schedule H, Line 75 |
| Standard Offer | $ 0.07064 | $ 35.32 | Standard Offer | $ 0.05614 | $ 28.07 | See Schedule H, Line 97 |
| Transmission | $ 0.02290 | $ 11.46 | Transmission | $ 0.02420 | $ 12.10 | See Schedule H, Line 86 |
| DSM/Renewable | $ 0.00230 | $ 1.15 | DSM | $ 0.00230 | $ 1.15 | |
| Total | | $ 74.90 | Total | | $ 68.18 | |
| | **Net Increase/(Decrease)** | | | | **$ (6.72)** | |
| | **Percent Increase/(Decrease)** | | | | **-9.0%** | |